UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _______**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD
TPL-007-1 TRANSMISSION SYSTEM PLANNED PERFORMANCE FOR
GEOMAGNETIC DISTURBANCE EVENTS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events and the accompanying definition of "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" ("Definition") for Commission approval. NERC submits the proposed Reliability Standard in response to the Commission's directive in Order No. 779 to develop a Reliability Standard that requires owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark geomagnetic disturbance events on the Bulk-Power System equipment and the Bulk-Power System as a whole.[4]

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[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2014).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[4] Order No. 779, *Reliability Standards for Geomagnetic Disturbances*, 143 FERC ¶ 61,147 ("Order No. 779").

NERC requests that the Commission approve proposed Reliability Standard TPL-007-1 (**Exhibit A**) and the Definition and find that the proposed Reliability Standard and Definition are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5] NERC also requests approval of: (i) the associated implementation plan (**Exhibit B**) for the proposed Reliability Standard; and (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibits A and G**). The NERC Board of Trustees adopted proposed Reliability Standard TPL-007-1 on December 17, 2014.

As required by Section 39.5(a)[6] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard TPL-007-1, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (**Exhibit C**), and a summary of the development history (**Exhibit I**).

I. EXECUTIVE SUMMARY

Geomagnetic disturbances ("GMDs") occur during solar storms when the sun ejects charged particles directed toward the earth, and the magnetic field associated with these charged particles interacts with the earth's magnetic field. This interaction could cause geomagnetically-induced currents (also known as "GICs") to flow in an electric power system through transmission lines and grounded transformer windings. GMDs can be of varying intensity, and their impact on an electric power system is dependent on a number of factors, including where the geomagnetic storm is located, the magnitude and direction of the geomagnetic fields, the

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5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

6 18 C.F.R. § 39.5(a) (2013).

7 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g,* Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672").

geomagnetic latitude of the electric power system, the local geology (i.e., electrical conductivity of the ground), and the characteristics of the electric power system.

During a GMD event, GIC flow in transformers can substantially increase absorption of reactive power and create harmonics, resulting in a risk of voltage instability or voltage collapse. In some cases, GIC flow in power transformers can cause increased transformer hot-spot heating, which can lead to equipment loss of life or damage. The science regarding the impacts of GMDs on electric power systems is still evolving, and much remains to be learned about the unique threat GMDs pose to the reliability of the Bulk-Power System. However, as the Commission noted in Order No. 779, "while there is an ongoing debate as to how a severe GMD event will most likely impact the Bulk-Power System, there is a general consensus that GMD events can cause wide-spread blackouts due to voltage instability and subsequent voltage collapse, thus disrupting the reliable operation of the Bulk-Power System."[8]

Proposed Reliability Standard TPL-007-1, together with Commission-approved Reliability Standard EOP-010-1, addresses the unique risks posed by a high-impact, low-frequency GMD event on the reliable operation of the Bulk-Power System and is responsive to the Commission's concerns articulated in Order No. 779. As the Commission established in Order No. 779, the proposed Reliability Standard "should include Requirements whose goal is to prevent instability, uncontrolled separation, or cascading failures of the Bulk-Power system when confronted with a benchmark GMD event."[9] The proposed standard is responsive to this directive by requiring owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of a defined GMD event (referred to herein as the

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[8] Order No. 779 at P 24 (internal citation omitted).

[9] Order No. 779 at P 84.

"Benchmark GMD Event") on Bulk-Power System equipment and the Bulk-Power System as a whole. The Benchmark GMD Event used to develop the proposed standard[10] is based on a 1-in-100 year frequency of occurrence, and is supported by rigorous technical analysis of modern measurement data and publicly-available models. The proposed Benchmark GMD Event sets a high benchmark for reliability, as it represents the most severe GMD event expected in a 100-year period as determined by a statistical analysis of recorded geomagnetic data. Additionally, the proposed standard specifies parameters for assessments that will identify impacts from this Benchmark GMD Event and requires corrective action to protect against instability, uncontrolled separation, and cascading failures of the Bulk-Power System.

The proposed Reliability Standard represents a significant milestone in NERC's ongoing efforts to understand and address the unique reliability risks that high-impact, low-frequency GMD events pose to the Bulk-Power System. The assessments and other actions required by the proposed standard complement the Operating Plans, Processes, and Procedures required in the Commission-approved EOP-010-1 Reliability Standard to address GMD impacts to the Bulk-Power System. Additionally, implementation of the proposed Reliability Standard will provide opportunities to further mature the tools, models, and techniques for assessing potential impacts of GMDs. Accordingly, for the reasons stated above and as discussed more fully herein, NERC requests that the Commission approve proposed Reliability Standard TPL-007-1 and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[10] *See* Order No. 779 at P 54 ("The Second Stage GMD Reliability Standard must identify what severity GMD events (*i.e.*, benchmark GMD events) that responsible entities will have to assess for potential impacts on the Bulk-Power System.")

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

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III. BACKGROUND

In Order No. 779, the Commission directed NERC to develop a set of Reliability Standards to address GMDs in two stages. In the first stage, NERC developed Reliability Standard EOP-010-1, requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. The Commission approved Reliability Standard EOP-010-1 in Order No. 797.[12] In the second stage, the Commission directed NERC to develop one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of

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11 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

12 Order No. 797, *Reliability Standard for Geomagnetic Disturbance Operations*, 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014) ("Order No. 797").

benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.[13] This second stage is addressed in proposed Reliability Standard TPL-007-1.

The following background information is provided below: (a) an explanation of the regulatory framework for NERC Reliability Standards; (b) an explanation of the NERC Reliability Standards development process; and (c) the history of Project 2013-03, Geomagnetic Disturbance Mitigation.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[14] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[15] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[16] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[17] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are

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13 Order No. 779 at PP 2, 67.

14 16 U.S.C. § 824o (2012).

15 *Id.* § 824o(b)(1).

16 *Id.* § 824o(d)(5).

17 18 C.F.R. § 39.5(a) (2014).

just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[18] and Section 39.5(c)[19] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Process

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[20] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[21] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus addresses certain of the criteria for approving Reliability Standards.[22] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

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[18] 16 U.S.C. § 824o(d)(2).

[19] 18 C.F.R. § 39.5(c)(1).

[20] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[21] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[22] 116 FERC ¶ 61,062 at P 250 (2006).

C. History of Project 2013-03, Geomagnetic Disturbance Mitigation

In June 2010, NERC identified that GMDs posed a serious threat to the reliable operation of the Bulk-Power System and that addressing this issue required significant staff and industry attention. Since that time, NERC has spent a substantial amount of time and effort working with experts across the North American power industry, U.S. and Canadian government agencies, transformer manufacturers, and other vendors to develop a scientifically sound understanding of the potential risks GMDs may pose to reliability.

In early 2011, a NERC-sponsored GMD Task Force was formed to "develop a technical white paper describing the evaluation of scenarios of potential GMD impacts, identifying key bulk power system parameters under those scenario conditions, and evaluating potential reliability implications of these incidents."[23] The GMD Task Force issued an interim report evaluating the effects of GMDs on the Bulk-Power System in February 2012.[24] Using an open process involving leading experts from industry, government and private researchers, and equipment and software vendors, the GMD Task Force has continued to support the development of tools and methods for assessing and mitigating GMD impacts.

In October 2012, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to direct that NERC submit to the Commission for approval proposed Reliability Standards that address the risks posed by GMDs to the reliable operation of the Bulk-Power System.[25] The NOPR stated that GMD vulnerabilities are not adequately addressed in the

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23 NERC, Board of Trustees Minutes, Exhibit J, at 1 (Nov. 4, 2010), *available at* http://www.nerc.com/docs/docs/bot/BOT-1110m-open-complete.pdf.

24 North American Electric Reliability Corp., *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* (February 2012) ("2012 NERC Interim GMD Report"), *available at* http://www.nerc.com/files/2012GMD.pdf.

25 *Reliability Standards for Geomagnetic Disturbances*, Notice of Proposed Rulemaking, 77 Fed. Reg. 64,935 (Oct. 24, 2012), 141 FERC ¶ 61,045 (2012) ("NOPR").

existing Reliability Standards, and that this therefore constitutes a reliability gap — because GMD events can cause the Bulk-Power System to collapse suddenly and can potentially damage equipment on the Bulk-Power System.[26]

In May 2013, the Commission issued Order No. 779 directing NERC to develop proposed Reliability Standards addressing GMD events in two stages, as explained above. In June 2014, the Commission issued Order No. 797, approving the first stage GMD Reliability Standard EOP-010-1. Reliability Standard EOP-010-1 mitigates the effects of GMDs on the Bulk-Power System by requiring applicable entities to implement Operating Plans and Operating Procedures or Processes. This petition addresses the second stage GMD Reliability Standard.

Proposed Reliability Standard TPL-007-1 is based on sound research and industry-leading engineering approaches. The standard drafting team that developed the proposed standard includes engineers, planners, and operators that are at the forefront of the industry's GMD activities, including an experienced representative from Canada, as well as a leading space weather researcher from NASA.[27] Several members of the standard drafting team are also leaders of the NERC GMD Task Force. Through the NERC GMD Task Force, the standard drafting team has worked collaboratively with scientific and technical organizations, equipment manufacturers, software vendors, and colleagues throughout the industry to develop state-of-the-art guidelines, modeling approaches, and technical resources that underpin the proposed Reliability Standard.

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26 *Id.* at P 4.

27 The standard drafting team roster for Project 2013-03, Geomagnetic Disturbance Mitigation is attached as **Exhibit J** to this petition.

IV. <u>JUSTIFICATION FOR APPROVAL</u>

As discussed in detail in **Exhibit C**, proposed Reliability Standard TPL-007-1—Transmission System Planned Performance for Geomagnetic Disturbance Events addresses the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As described more fully herein and in **Exhibit C**, the proposed Reliability Standard contains significant reliability benefits for the Bulk-Power System and addresses the directives and concerns identified by the Commission in Order No. 779.

The purpose of proposed Reliability Standard TPL-007-1 is to establish requirements for planned Transmission system performance during GMD events. The provisions of the proposed standard raise the level of preparedness among applicable entities by requiring these entities to plan for the reliable operation of the Bulk-Power System during the Benchmark GMD Event - a severe, 1-in-100 year GMD event.

The proposed standard includes the proposed definition of GMD Vulnerability Assessment. GMD Vulnerability Assessments provide the framework for evaluating potential impacts of the Benchmark GMD Event on Bulk-Power System equipment and the Bulk-Power System as a whole. Using a planning approach, the proposed Reliability Standard includes requirements for coordinating responsibilities among applicable entities, developing and maintaining models, establishing performance criteria and assessing performance, exchanging relevant information necessary to coordinate the actions of applicable entities, and developing Corrective Action Plans to address performance deficiencies.

This section of the petition addresses: (i) the description of the proposed Definition; (ii) the applicability of proposed Reliability Standard TPL-007-1; (iii) the description and technical basis for the Benchmark GMD Event; (iv) the description and technical basis for thermal impact assessments for power transformers; (v) the description of the proposed Requirements; and (vi) the description of the proposed implementation plan. This section also provides a brief summary of how proposed Reliability Standard TPL-007-1 addresses the Commission's directives from Order No. 779 and concludes with a discussion of the enforceability of the proposed standard.

A. Proposed Definition of "Geomagnetic Disturbance Vulnerability Assessment or "GMD Vulnerability Assessment"

The following Definition is proposed for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment**: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

The GMD Vulnerability Assessment is an integral part of the proposed Reliability Standard and provides the framework for evaluating potential impacts of the Benchmark GMD Event on Bulk-Power System equipment and the Bulk-Power System as a whole.[28] It also provides the means to allow for the identification of "facilities most at-risk from severe geomagnetic disturbance" in accordance with Order No. 779.[29]

Figure 1 below provides a graphical depiction of the GMD Vulnerability Assessment process. A summary description follows.

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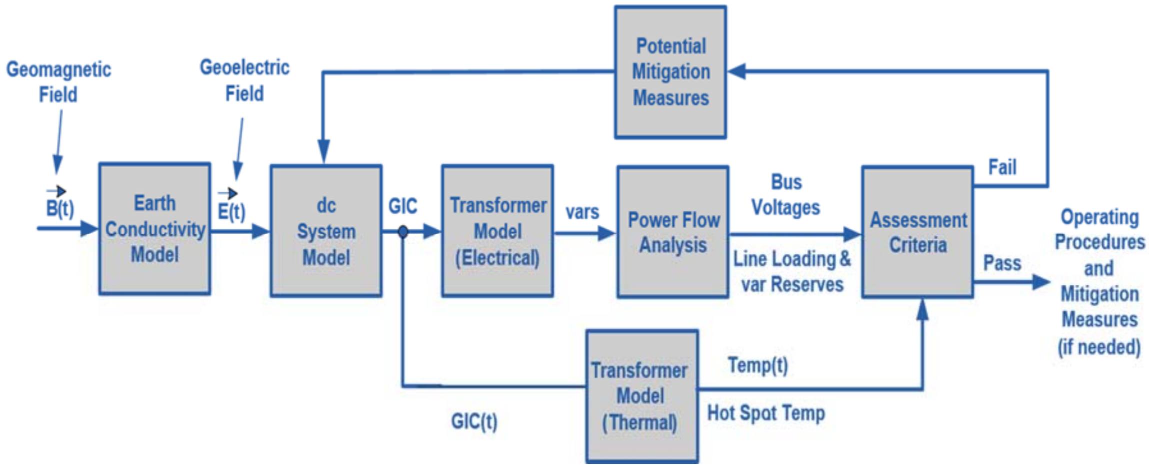
[28] *See* Order No. 779 at P 67. *See also* Order No. 779 at P 24 ("[T]here is a general consensus that GMD events can cause wide-spread blackouts due to voltage instability and subsequent voltage collapse, thus disrupting the reliable operation of the Bulk-Power System.")

[29] Order No. 779 at P 51.

Figure 1. GMD Vulnerability Assessment Process



In the GMD Vulnerability Assessment process outlined in the diagram above, the transmission system GIC flows are calculated by applicable Transmission Planners and Planning Coordinators for the Benchmark GMD Event using GIC system models. These models represent the direct current (dc) characteristics of the transmission system, including applicable power transformers, transmission lines, GIC reduction or blocking devices, and reactive power compensation devices.[30] The GIC flow information at each applicable power transformer is used with power transformer electrical models to determine the maximum reactive power losses; the maximum reactive power losses are applied to the power flow analysis required by the GMD Vulnerability Assessment. Additionally, using transformer thermal models and GIC flow information at each applicable power transformer, Transmission Owners and Generator Owners conduct transformer thermal impact assessments to determine the additional hot-spot heating that could be caused by the Benchmark GMD Event. Results of the power flow analysis and transformer thermal impact assessments are evaluated according to assessment criteria. When

[30] NERC GMD Task Force, Application Guide for Computing Geomagnetically-Induced Current in the Bulk-Power System at 18-25 (December 2013), *available at* http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf. ("GIC Application Guide")

mitigation measures are determined to be necessary, steps in the GMD Vulnerability Assessment process are repeated to recalculate GIC flows and reevaluate transmission system performance. The Geomagnetic Disturbance Planning Guide, developed by the NERC GMD Task Force in 2013, provides detailed technical guidance to support GMD-specific studies that are used in the GMD Vulnerability Assessment process.[31]

As described more fully below, proposed Reliability Standard TPL-007-1 contains requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary.

B. Applicability of Proposed Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Proposed Reliability Standard TPL-007-1 is applicable to: (1) Planning Coordinators with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (2) Transmission Planners with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (3) Transmission Owners that own a Facility or Facilities that include a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; and (4) Generator Owners that own a Facility or Facilities that include a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.[32]

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[31] NERC GMD Task Force, *Geomagnetic Disturbance Planning Guide* (Dec. 2013), *available at* http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf ("GMD Planning Guide").

[32] A power transformer with a "high side wye-grounded winding" refers to a power transformer with windings on the high voltage side that are connected in a wye configuration and have a grounded neutral connection.

The applicability section of proposed Reliability Standard TPL-007-1 is consistent with Order No. No. 779 and Order No. 797. As the Commission noted in Order No. 779, "[b]ecause many Bulk-Power System transformers are grounded, the GIC appears as electrical current to the Bulk-Power System and flows through the ground connection and conductors, such as transformers and transmission lines."[33] The applicability of proposed Reliability Standard TPL-007-1 recognizes the technical considerations of the impact of a GMD event on the Bulk-Power System.

Proposed Reliability Standard TPL-007-1 complements the stage one GMD Reliability Standard, EOP-010-1, which is applicable to Reliability Coordinators and those Transmission Operators with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV. EOP-010-1 requires these entities to implement Operating Plans and Operating Procedures or Processes to mitigate the effects of GMDs on the Bulk-Power System.

The standard drafting team determined that a voltage threshold of greater than 200 kV for proposed Reliability Standard TPL-007-1 is appropriate because the effect of GICs in networks less than 200 kV would have a negligible impact on the reliability of the interconnected transmission system. This finding is supported by operating experience and the preponderance of peer-reviewed studies on GMD effects[34] and is consistent with the scope and purpose of both the proposed Reliability Standard and the Commission-approved EOP-010-1 Reliability Standard.

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33 Order No. 779 at P 6 (citing 2012 NERC Interim GMD Report at ii).

34 *See* Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard EOP-010-1, RM14-1-000 (Nov. 14, 2013) at Exhibit D.

C. The Benchmark GMD Event

Proposed Reliability Standard TPL-007-1 requires applicable entities to conduct initial and on-going assessments of the potential impact of the Benchmark GMD Event on Bulk-Power System equipment and the Bulk-Power System as a whole. The purpose of the Benchmark GMD Event is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by the proposed TPL-007-1 Reliability Standard. The Benchmark GMD Event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. As the Commission noted in Order No. 779, the Benchmark GMD Event must be technically justified to "define the scope of the Second Stage GMD Reliability Standards (i.e., responsible entities should not be required to assess GMD events more severe than the benchmark GMD events)."[35] The proposed Benchmark GMD Event is technically supported by modern measurement data and publicly-available models. Further, the proposed Benchmark GMD Event sets a high benchmark for reliability, as it represents the most severe GMD event expected in a 100-year period as determined by a statistical analysis of recorded geomagnetic data.

As discussed below, the proposed Benchmark GMD Event is described in terms that can be directly applied to the performance of GMD Vulnerability Assessments required by proposed Reliability Standard TPL-007-1. Further, the proposed Benchmark GMD Event supports the assessment of known GMD-related vulnerabilities with the potential to impact the reliable operation of the Bulk-Power System, such increased reactive power consumption in power transformers, loss of reactive power sources, and increased transformer hot-spot heating. The Benchmark Geomagnetic Disturbance Event Description white paper included as **Exhibit D**

[35] Order No. 779 at P 2.

provides additional description of the parameters of the Benchmark GMD Event, explains the technical details that led to the selection of these parameters, and demonstrates how they should be applied to obtain entity-specific values.

Thus, the proposed Benchmark GMD Event addresses the Commission's directive to specify what severity GMD event an entity must assess for potential impacts on the Bulk-Power System and defines the scope for proposed Reliability Standard TPL-007-1.

1. The Proposed Benchmark GMD Event Sets a High Benchmark for Reliability

The proposed Benchmark GMD Event sets a high benchmark for reliability, as it represents the most severe GMD event expected in a 100-year period as determined by a statistical analysis of recorded geomagnetic data. The Benchmark GMD Event used to develop the proposed standard is based on a 1-in-100 year frequency of occurrence, which is a conservative planning criterion for electric power systems.[36] A 1-in-100 year occurrence rate addresses risks from a GMD event on the order of the March 1989 GMD event, which has caused known impacts to the Bulk-Power System, and reasonably protects against impacts from more extreme GMD events.

The March 1989 GMD event, which impacted the North American Bulk-Power System by causing a blackout in Quebec,[37] is considered to be a 1-in-50 year GMD event and one of the strongest for which detailed and accurate records are available.[38] The Carrington Event of 1859 was stronger than the March 1989 GMD event, but limited information is available to accurately

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[36] For additional information, *see* Benchmark Geomagnetic Disturbance Event Description (**Exhibit D**) at 5 and Appendix I.

[37] For more information about the March 1989 GMD event, *see* 2012 NERC Interim GMD Report at i.

[38] *See* Jeffrey J. Love, *Credible Occurrence Probabilities for Extreme Geophysical Events: Earthquakes, Volcanic Eruptions, Magnetic Storms*, GEOPHYSICAL RES. LETTERS (May 2012) (hereinafter "Love (2012)").

describe this event.[39] A Carrington-type event is considered to be a 1-in-150 year GMD event, but uncertainty in the occurrence rate is even greater than that for the March 1989 GMD event.[40] Thus, the selection of a 1-in-100 year occurrence rate for the Benchmark GMD Event provides a high level of assurance that the Bulk-Power System is planned for reliable operations during a severe GMD event.

The Benchmark GMD Event is technically-supported by the use of modern measurement data and statistical techniques. The Benchmark GMD Event expands on work conducted by the NERC GMD Task Force in which 1-in-100 year geoelectric field amplitudes were calculated from a well-known source of dense high-resolution geomagnetic data commonly used in space weather research.[41] This approach was adapted to develop the Benchmark GMD Event which supports, through the GMD Vulnerability Assessments required by proposed Reliability Standard TPL-007-1, the identification of GMD impacts with the potential to cause "instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[42] Additional extreme value analysis was performed to determine that the geoelectric field associated with the proposed Benchmark GMD Event exceeds the 95% confidence bound, which indicates that the likelihood of a GMD event exceeding the proposed benchmark during a 100-year period is low.

[39] This is the largest recorded GMD event, named after the British astronomer Richard Carrington.

[40] *See id.*

[41] A. Pulkkinen et al., *Generation of 100-year Geomagnetically Induced Current Scenarios*, SPACE WEATHER (2012); *see also* 2012 NERC Interim GMD Report at 20-23.

[42] The Commission indicated in Order No 779 that the proposed Reliability Standard should include "Requirements whose goal is to prevent instability, uncontrolled separation, or cascading failures of the Bulk-Power System when confronted with a benchmark GMD event." Order No. 779 at P. 84. Appendix I to the Benchmark Geomagnetic Disturbance Event Description white paper (**Exhibit D**) describes how the Benchmark GMD Event was developed to support assessment of these impacts.

2. The Benchmark GMD Event Can be Directly Applied to the Performance of GMD Vulnerability Assessments

The proposed Benchmark GMD Event is described by parameters that are usable by applicable entities in conducting their GMD Vulnerability Assessments. While there are a variety of measurements and indices that can be used to describe GMD conditions,[43] assessment of GMD effects on an electric power system requires the calculation of GICs that result from the geoelectric fields produced by the earth's varying magnetic field during a GMD event. The geoelectric field produced during a GMD event is dependent upon the geomagnetic latitude and earth conductivity where the electric power system is located and is the direct physical parameter leading to the creation of GICs, as described in technical references.[44] Consequently, the proposed Benchmark GMD Event is described in terms of the geoelectric field (V/km) for use by applicable entities in conducting GMD Vulnerability Assessments.

Although the Benchmark GMD Event is described in proposed Reliability Standard TPL-007-1 as a single event, it includes several components within its framework for assessing GMD vulnerabilities. The Benchmark GMD Event includes technically-justified scaling factors to enable applicable entities to tailor the geoelectric field to their specific location for conducting GMD Vulnerability Assessments. This accounts for differences in the intensity of a GMD event due to geographical considerations, such as geomagnetic latitude and local earth conductivity.[45] The geomagnetic latitude scaling factor is based on modern global scientific observations for

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[43] These include the A index, K index, and G scales that are used by space weather monitoring and forecasting organizations to describe geomagnetic storm severity and the disturbance storm time (Dst) index measuring the amplitude of the main phase disturbance for a magnetic storm. Many of these indices were originally designed for scientific or research purposes.

[44] *See generally* GIC Application Guide.

[45] *See* Benchmark Geomagnetic Disturbance Event Description (**Exhibit D**).

major storms since late 1980s.[46] Scaling factors for earth conductivity take into account that the induced geoelectric field depends on local earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure. The Benchmark GMD Event includes default scaling factors for earth conductivity based on publicly-available earth models. These technically-justified scaling factors allow the applicable entities of proposed Reliability Standard TPL-007-1 to perform GMD Vulnerability Assessments according to entity-specific criteria.[47]

3. The Proposed Benchmark GMD Event Includes the Necessary Parameters to Support Assessment of Known GMD Related Vulnerabilities

The Benchmark GMD Event also includes the parameters necessary to support assessment of various known GMD-related vulnerabilities that have the potential to impact the reliable operation of the Bulk-Power System. GMD events have the potential to produce electric power system impacts, such as increased reactive power consumption in power transformers, loss of reactive power sources, and increased transformer hot-spot heating. For the purpose of conducting GMD Vulnerability Assessments, some impacts, such as reactive power losses, should be considered as having a nearly-instantaneous effect on an electric power system. Other impacts, like increased transformer hot spot heating, affect an electric power system over longer periods of time during a GMD event, and thus should not be assumed to occur instantaneously. To address these considerations, the proposed Benchmark GMD Event includes both: (i) a peak

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[46] The studied storms reveal that the propagation of auroral boundaries stops at about 50 degrees of geomagnetic latitude. This is a repeating feature of the geospace system under strong solar driving conditions and scaling over the band between 40-60 degrees of geomagnetic latitude. *See* C. Ngwira and A. Pulkinnen et al., *Extended Study of Extreme Geoelectric Field Event Scenarios for Geomagnetically Induced Current Applications*, 11 SPACE WEATHER 121 (2013)).

[47] In Order No. 779, the Commission recognized the need for tailored assessments based on "geographic location and geology" and stated the expectation that "vulnerability assessments would be based on uniform criteria (e.g., geographic location and geology) but the values for such criteria would be entity-specific." Order No. 779 at P 70.

geoelectric field magnitude for assessing near-instantaneous voltage impacts, as discussed previously; and (ii) a waveshape for calculating a GIC time-series that is used in assessing thermal impacts in power transformers, as discussed in more detail below.

An analysis of the high resolution magnetometer data from several GMD events, as shown in the Benchmark Geomagnetic Disturbance Event Description white paper **(Exhibit D)**, indicates that the March 1989 GMD event provides a conservative worst-case waveshape for conducting transformer thermal impact assessments. Consequently, the Benchmark GMD Event waveshape is based on magnetometer data of the March 1989 GMD event recorded by the Ottawa geomagnetic observatory.[48] To conduct a transformer thermal assessment, an applicable Transmission Owner or Generator Owner uses GIC flows based on the March 1989 GMD event waveshape, magnified to the statistically-derived 1-in-100 year geoelectric field strength. Thus, the Benchmark GMD Event provides a 1-in-100 year benchmark for assessing GMD impacts to Bulk-Power System equipment.

4. Additional Benchmark GMD Event Considerations in the Standards Development Process

Past reports and ongoing scientific research reflect varying perspectives on the potential severity of GMD events. As the Commission recognized in Order No. 779, there is no consensus on benchmark GMD events for assessing the vulnerability of the Bulk-Power System.[49] Accordingly, the proposed Benchmark GMD Event was evaluated throughout the development of the proposed standard, resulting in a benchmark supported by rigorous technical analysis of

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[48] In the Benchmark Geomagnetic Disturbance Event Description white paper (**Exhibit D**), an analysis of available GMD events with 10-second magnetic data was conducted to determine that the March 1989 GMD event represented the most conservative selection. *See id.* at 15-16.

[49] *See* Order No. 779 at P 71 ("[T]here is currently no consensus on benchmark GMD events, and the Commission does not identify specific benchmark GMD events for NERC to adopt. Instead, this issue should be considered in the NERC standards development process so that any benchmark GMD events proposed by NERC have a strong technical basis.").

modern measurement data and publicly-available models. The use of modern measurement data and statistical techniques provides for a state-of-the-art Benchmark GMD Event for use in GMD Vulnerability Assessments required by proposed Reliability Standard TPL-007-1.

As discussed above, the proposed Benchmark GMD Event is more intense than the March 1989 GMD event to appropriately address the risks of a high-impact, low frequency GMD event.[50] The standard drafting team also examined other historical GMD events in developing the proposed Benchmark GMD Event, some of which are described below.

Geomagnetic Storm of 1921

Some reports examining the effects of GMD events on the power system suggested that the geomagnetic storm of 1921 is a 1-in-100-year event. These reports described the potential impacts a GMD event of this magnitude could have on the grid.[51] After much consideration, the standard drafting team determined, that with limited direct observations of the magnetic fields, it was not possible to include the 1921 event in a rigorous determination of the 1-in-100-year Benchmark GMD Event characteristics. Without this data, it was also not possible to perform a more-detailed analysis of the impacts of the 1921 event on the modern electric power system.[52]

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50 Some estimate the March 1989 GMD Event is a 1-in-50 year event. *See* Love (2012), *supra* n. 38. The Benchmark GMD Event magnifies the March 1989 GMD event waveshape to the statistically-derived 1-in-100 year geoelectric field strength to provide a 1-in-100 year intensity.

51 *See* Oak Ridge National Laboratory, *FERC EMP-GIC Metatech Report Meta-R-319* at 3-22 (January 2010), *available at* http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf ("Meta R-319"); *see also* National Research Council of the National Academies, *Severe Space Weather Events – Understanding Societal and Economic Impacts, a Workshop Report* at 3, 77 (2008), *available at* http://www.nap.edu/catalog/12507/severe-space-weather-events--understanding-societal-and-economic-impacts.

52 The 2011 JASON Summer Study sponsored by U.S. Department of Homeland Security reported that the authors were "not convinced that the worst-case scenario [of Meta-R-319] is plausible." *See* JASON, *Impacts of Severe Space Weather on the Electric Grid*, *JSR-11-320* at 2 (2011).

Carrington Event of 1859

Another extreme GMD event that has been considered by some researchers as a basis for risk assessment is the Carrington Event of 1859. Like the 1921 GMD event, high-quality geomagnetic field data are not available that would allow direct determination of the geoelectric fields experienced during the Carrington Event. Research is being conducted to examine the capability for complex dynamic space weather prediction models to determine the geoelectric fields produced by Carrington-like space weather conditions.[53] However, at present, these efforts are a basic research endeavor aimed at assessing performance of the dynamic space weather prediction models. Furthermore, the occurrence rate of a Carrington-type GMD event is uncertain, but it is estimated to be a 1-in-150 year event, as discussed previously.[54]

July 2012 Coronal Mass Ejection

Some researchers have examined, through simulations, the potential geomagnetic effects of a powerful coronal mass ejection observed by NASA spacecraft in July 2012.[55] Since the July 2012 coronal mass ejection did not impact the earth, research analyses require relying on space science models for estimating its geomagnetic impact. Due to the complex nature of the space weather phenomena and relatively immature state of modern space science models, dynamic model-based assessments contain inherent uncertainties that are not always well known. While events such as the July 2012 coronal mass ejection provide a valuable research opportunity for the space weather community to improve its space weather prediction modeling capabilities, the

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53 C. Ngwira et al., *Modeling Extreme "Carrington-type" Space Weather Events Using Three-dimensional Global MHD Simulations*, 119 J. OF GEOPHYSICAL RES.: SPACE PHYSICS 4456 (2014)).

54 *See* Love (2012), *supra* n. 38.

55 *See* C. Ngwira et al., *Simulation of the 23 July 2012 Extreme Space Weather Event: What if This Extremely Rare CME was Earth Directed?*, 11 SPACE WEATHER 671 at 677 (2013) (concluding that "had the 23 July CME hit Earth, there is a possibility that it could have produced comparable or slightly larger geomagnetically induced electric fields to those produced by previously observed Earth directed events such as the March 1989 storm or the Halloween 2003 storms."); *see also* D.N. Baker et al., *A Major Solar Eruptive Event in July 2012: Defining Extreme Space Weather Scenarios*, 11 SPACE WEATHER 585 (2013).

standard drafting team determined that observed geomagnetic data is more appropriate for direct application to the Benchmark GMD Event description and the proposed Reliability Standard.

Given the varying nature and degree of scientific uncertainty in the events described above, the proposed Reliability Standard and accompanying Benchmark GMD Event incorporate rigorous technical analysis that is representative of the complex nature of space weather phenomena, and therefore reflects a balanced and practical approach in the proposed TPL-007-1 Reliability Standard.

D. Transformer Thermal Impact Assessment

Large power transformers connected to the high voltage and extra high voltage Transmission systems can experience both increased winding and structural hot spot heating as a result of GIC flow during GMD events. Proposed Reliability Standard TPL-007-1 requires owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers would be able to withstand the thermal effects associated with the Benchmark GMD Event. The Transformer Thermal Impact Assessment White Paper (**Exhibit E)** discusses methods that can be employed to conduct such analyses, including example calculations.

Transformers are exempt from the thermal impact assessment requirement included in the proposed standard if the maximum effective GIC in the transformer is less than 75 A per phase during the Benchmark GMD Event as determined by an analysis of the system.[56] Based on available power transformer measurement data and as described in the Screening Criterion for Transformer Thermal Impact Assessment white paper (**Exhibit F)**, transformers with an

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[56] *See* Screening Criterion for Transformer Thermal Impact Assessment (**Exhibit F**) for technical justification of the thermal impact screening criterion. The 75 A per phase threshold is based on the Benchmark GMD Event waveshape and resulting GIC time series in order to identify those applicable transformers that may experience excessive hot spot heating during the Benchmark GMD Event. The criterion should not be interpreted as a continuous value of 75 A per phase effective GIC.

effective GIC of less than 75 A per phase during the Benchmark GMD Event are unlikely to exceed known temperature limits established by technical organizations. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements of single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

E. Requirements in Proposed Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

The purpose of proposed Reliability Standard TPL-007-1 is to establish requirements for Transmission system planned performance during GMD events. The proposed Reliability Standard consists of seven Requirements, Table 1 – Steady State Planning Events, and Attachment 1 – Calculating Geoelectric Fields for the Benchmark GMD Event. Table 1 sets forth requirements for System steady state performance. Attachment 1 explains how to calculate geoelectric fields to establish the Benchmark GMD Event.

Proposed Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planner(s), to identify the responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). Proposed Requirements R2, R3, R4, R5, and R7 therefore refer to the "responsible entity, as determined by Requirement R1," when identifying which applicable Planning Coordinators or Transmission Planners are responsible for maintaining models and performing the necessary study or studies.

Proposed Requirement R2 is intended to ensure that the responsible entities maintain models for performing the studies needed to complete GMD Vulnerability Assessment(s) required by proposed Requirement R4. Proposed Requirement R3 requires the responsible entities to have criteria for acceptable System steady state voltage performance during a Benchmark GMD Event.

Proposed Requirement R4 requires the responsible entities to complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months.

Proposed Requirement R5 requires the responsible entities to provide GIC flow information to Transmission Owners and Generator Owners that own a Bulk Electric System (BES) power transformer in the planning area. This information is necessary for applicable Transmission Owners and Generator Owners to conduct the thermal impact assessments required by proposed Requirement R6. Proposed Requirement R6 requires applicable Transmission Owners and Generator Owners to conduct thermal impact assessments where the maximum effective GIC value provided in proposed Requirement R5, Part 5.1 is 75 A per phase or greater.

Proposed Requirement R7 requires the responsible entities to develop a Corrective Action Plan when its GMD Vulnerability Assessment indicates that its System does not meet the performance requirements of Table 1 – Steady State Planning Events. The Corrective Action Plan must address how the performance requirements will be met, must list the specific deficiencies and associated actions that are necessary to achieve performance, and must set forth a timetable for completion.

Collectively, the proposed Requirements, Table 1, and Attachment 1 address the Commission's directives in Order No. 779 and are intended to establish requirements for Transmission system planned performance during GMD events. Provided below is a justification of the proposed Reliability Standard on a requirement-by-requirement basis.

Proposed Requirements

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Proposed Requirement R1 requires applicable Planning Coordinators, in conjunction with Transmission Planner(s), to identify the responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). This determination sets forth the roles and responsibilities for applicable Planning Coordinators and Transmission Planners for Requirements R2 through R5 and R7 of proposed Reliability Standard TPL-007-1 and is designed to allow for differences in regional organizations and to provide flexibility. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s). Proposed Requirement R1 ensures that the responsibilities within a planning area are clearly articulated and understood, particularly where there are joint responsibilities.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Proposed Requirement R2 builds upon Requirement R1, and it is intended to ensure that the responsible entities maintain System models and GIC System models for performing the studies needed to complete GMD Vulnerability Assessment(s) as required in proposed

Requirement R4. A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow, which is then used to determine transformer Reactive Power absorption and transformer thermal response.

The GIC System model includes all power transformer(s) in the planning area with a high side, wye-grounded winding with terminal voltage greater than 200 kV. Technical guidance for developing the GIC System model is provided in the GIC Application Guide.

The System model specified in proposed Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System. Steady state power flow analysis is required by the GMD Vulnerability Assessment, as specified in proposed Requirement R4.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1.

Proposed Requirement R3 specifies that the responsible entity shall establish the System steady state voltage performance criteria for use in the GMD Vulnerability Assessment. Steady state voltage limits are an example of System steady state performance criteria. Proposed Requirement R3 provides flexibility for development of more sophisticated methods of determining voltage stability.

R4. Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis.

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1. If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Proposed Requirement R4 requires the responsible entities (as determined in Requirement R1) to complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. The "Near Term Transmission Planning Horizon" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "The transmission planning period that covers Year One through five."[57] Requirement R4 Part 4.1 specifies that studies must be conducted for both On-Peak Load and Off-Peak Load conditions in order to account for a range of System Reactive Power resources in the assessment. Table 1 – Steady State Planning Events establishes uniform performance criteria and assessment details. Because some devices that are susceptible to harmonic impacts may affect System steady state

[57] "Year One" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013."

performance, Table 1 requires responsible entities to remove such devices from the analysis when assessing System performance. Proposed Requirement R4 establishes consistent parameters for the responsible entities to conduct initial and on-going GMD Vulnerability Assessments that meet the directives in Order No. 779.[58]

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include:

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

Proposed Requirement R5 is intended to ensure that Transmission Owners and Generator Owners can access GIC flow information in order to perform the transformer thermal impact assessment required in proposed Requirement R6. GIC information should be provided in accordance with proposed Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD. The GIC flow information specified in Part 5.1 and Part 5.2 of proposed Requirement R5 support various methods for

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[58] Order No. 779 directed that "[e]ach responsible entity under the Second Stage GMD Reliability Standards would then be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR and adopted in this Final Rule." Order No. 779 at P. 67.

performing transformer thermal impact assessments. These methods are described in the Transformer Thermal Impact Assessment White Paper, included as **Exhibit E** to this petition.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The thermal impact assessment shall:

- **6.1. Be based on the effective GIC flow information provided in Requirement R5;**
- **6.2. Document assumptions used in the analysis;**
- **6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and**
- **6.4. 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, Part 5.1.**

Proposed Requirement R6 requires Transmission Owners and Generator Owners to conduct thermal impact assessments for their solely and jointly-owned power transformers with a high side, wye-grounded winding with terminal voltage greater than 200 kV where the maximum effective GIC value for the worst case geoelectric field orientation for the Benchmark GMD Event described in Attachment 1 is 75 A per phase or greater. Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 75 A per phase during the Benchmark GMD Event as determined by an analysis of the system. Based on available power transformer measurement data, transformers with an effective GIC of less than 75 A per phase during the Benchmark GMD Event are unlikely to exceed known temperature limits established by technical organizations. Additional information is available in the Screening Criterion for Transformer Thermal Impact Assessment white paper, included as **Exhibit F** to this petition.

Thermal impact assessments are provided to the responsible entity, as determined in proposed Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (Requirement R4) and the Corrective Action Plan (Requirement R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not pose a risk of Bulk-Power System instability, uncontrolled separation, or Cascading.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall:

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

• Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.

• Installation, modification, or removal of Protection Systems or Special Protection Systems.

• Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan.

• Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

When a responsible entity's GMD Vulnerability Assessment does not meet the performance requirements of Table 1 – Steady State Planning Events, proposed Requirement R7 mandates that it must develop a Corrective Action Plan addressing how the performance requirements of Table 1 will be met. A "Corrective Action Plan" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "[a] list of actions and an associated timetable for implementation to remedy a specific problem." The Corrective Action Plan must list the System deficiencies and associated actions needed to achieve performance as set forth in Section 7.1 of proposed Requirement R7. To ensure accountability, the responsible entities must review these deficiencies in subsequent GMD Vulnerability Assessments until such time that the System meets the performance requirements of Table 1. Proposed Requirement R7 is technology-neutral and provides flexibility for the responsible entities to select appropriate mitigation strategies, subject to the vulnerabilities identified in the assessments and as supported by technical guidance. These mitigating strategies may include installation of hardware (e.g., GIC blocking or monitoring devices), equipment upgrades, training, or enhanced Operating Procedures.[59] With this range of potential mitigation strategies, it is appropriate to provide flexibility to the responsible entities with respect to establishing timetables for completion.

The Corrective Action Plan must be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need. This provision ensures that there is coordination and communication among the functional entities. The provision of information in proposed Requirement R7 Part 7.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

For the reasons described above, the proposed Reliability Standard is just and reasonable and is designed to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System as a result of a Benchmark GMD Event through the performance of initial and on-going GMD Vulnerability Assessments.

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[59] Mitigating measures and approaches, including geomagnetically-induced current reduction devices, monitoring, and system reconfiguration, are discussed in Chapters 9 and 10 of the 2012 NERC Interim GMD Report and Chapter 5 of the GMD Planning Guide (Dec. 2013).

F. Implementation of Proposed Reliability Standard TPL-007-1

The implementation plan for proposed Reliability Standard TPL-007-1, included as **Exhibit B** to this petition, provides a multi-phased approach to implementation over a five-year period as follows:

- Requirement R1, pertaining to establishing responsibilities among applicable Planning Coordinators and Transmission Planners, shall become effective on the first day of the first calendar quarter that is **six months** after regulatory approval.[60]
- Requirement R2, requiring the maintenance of System models and GIC System models for performing the study or studies needed to complete GMD Vulnerability Assessments, shall become effective on the first day of the first calendar quarter that is **18 months** after regulatory approval.
- Requirement R5, which requires the responsible Planning Coordinators and Transmission Planners to provide GIC flow information to applicable Transmission Owners and Generator Owners for the transformer thermal impact assessments specified in Requirement R6, shall become effective on the first day of the first calendar quarter that is **24 months** after regulatory approval.
- Requirement R6, which requires applicable Transmission Owners and Generator Owners to conduct thermal impact assessments and provide the results to the responsible Planning Coordinators or Transmission Planners, shall become

[60] "Regulatory approval" refers specifically to the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. The implementation plan also provides effective dates where approval by an applicable governmental authority is not required for a standard to go into effect.

effective on the first day of the first calendar quarter that is **48 months** after regulatory approval.

- Requirements R3, R4, and R7, which address establishing criteria for acceptable System steady state voltage performance during the Benchmark GMD Event, performing GMD Vulnerability Assessments, and developing Corrective Action Plans to address identified vulnerabilities, respectively, shall become effective on the first day of the first calendar quarter that is **60 months** after regulatory approval.

The proposed implementation plan provides for the proper sequencing of system and equipment assessments performed by various applicable entities to build an overall assessment of GMD vulnerability. In accordance with Order No. 779, the proposed implementation plan provides an appropriate time period for applicable entities to obtain tools, models, and data required for GMD Vulnerability Assessments.[61] In many cases, applicable entities will be developing GIC system models needed for proposed Requirement R2 and obtaining transformer thermal models needed for proposed Requirement R6 for the first time. The proposed implementation plan allows sufficient time for the necessary analysis and coordination. The proposed implementation plan also provides the necessary time for the development of viable Corrective Action Plans to address identified vulnerabilities. These Corrective Action Plans may require entities to develop, perform, or validate new or modified studies, assessments, or procedures to meet the requirements of the proposed standard. Further, some mitigation measures may have significant budget, siting, or construction planning requirements. Therefore,

[61] Order No. 779 at P 68 ("When developing the Second Stage GMD Reliability Standards implementation schedule, NERC should consider the availability of validated tools, models, and data necessary to comply with the Requirements.").

the five-year phased implementation plan reflects an appropriate and realistic timeframe for compliance with proposed Reliability Standard TPL-007-1.

G. Commission Directives and Issues Addressed

As explained in **Exhibit H**, the proposed Reliability Standard addresses all of the Commission's directives in Order No. 779 with respect to Stage 2 of the GMD Reliability Standards. In addition, the proposed Reliability Standard addresses a number of concerns and issues identified for consideration by the Commission.

Provided below is an explanation of how the proposed Reliability Standard addresses each Commission directive or how it addresses a concern or issue identified by the Commission in Order No. 779.

1. Benchmark GMD Event and Timing: Order No. 779, Paragraph 2

In Order No. 779, the Commission directed NERC to "submit, within 18 months of the effective date of this Final Rule, one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole."[62] The Commission also stated that the proposed Reliability Standard must "identify 'benchmark GMD events' that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System."[63]

Proposed Reliability Standard TPL-007-1 requires initial and on-going vulnerability assessments of the impact of a Benchmark GMD Event, as described herein. The severity of GMD events is specified in the Benchmark GMD Event, which is set forth in Attachment 1. The

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62 Order No. 779 at P 2.

63 *Id.*

benchmark provides a defined event for assessing system performance as required by the proposed Reliability Standard. It also defines the geoelectric field values used to compute GIC flows for a GMD Vulnerability Assessment.

Order No. 779 became effective on July 22, 2013. The instant petition is being submitted within 18 months, in compliance with the Commission's directive.[64]

2. Costs and Benefits: Order No. 779, Paragraph 28

In Order No. 779, the Commission stated that it "expect[ed] NERC and industry [to] consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards."[65] While not a directive, NERC solicited comments on mitigation costs from stakeholders during formal comment periods in order to address the Commission's concerns related to consideration of costs.

The standard drafting team chose a planning standard approach to meet the directives for the second stage GMD Reliability Standard, which allows applicable entities flexibility to select mitigation measures based on a variety of considerations, including costs. Like other existing planning standards, proposed Reliability Standard TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, applicable entities can evaluate options using criteria which could include cost considerations.

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64 Order No. 779 at P 18.

65 Order No. 779 at P 28.

3. Identification of Facilities and Wide-Area Assessment: Order No. 779, Paragraph 51

In Order No. 779, the Commission directed NERC to "'identify facilities most at-risk from severe geomagnetic disturbance' and 'conduct wide-area geomagnetic disturbance vulnerability assessment' as well as give special attention to those Bulk-Power System facilities that provide service to critical and priority loads."[66]

When fully implemented, proposed Reliability Standard TPL-007-1 will enable wide-area assessment of GMD impact. Through the standard development process, industry has provided projections on the time required for obtaining validated tools, models, and data necessary for conducting GMD Vulnerability Assessments. The five-year phased implementation plan has been tailored accordingly and reflects a realistic timeline for the performance of GMD Vulnerability Assessments.

Corrective Action Plans required by proposed Reliability Standard TPL-007-1 provide the means to address risk to all applicable facilities from a Benchmark GMD Event, not only those determined to be most at-risk in wide-area assessments. Additionally, the proposed Reliability Standard enhances NERC's ability to further assess the reliability risks that GMDs pose to the Bulk-Power System through the reliability assessment functions described in Section 800 of the NERC Rules of Procedure. Once the proposed standard is fully implemented, NERC and the Regional Entities will be better able to assess further the potential impacts of GMD events on the Bulk-Power System as a whole.

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66 Order No. 779 at P 51 (internal citation omitted).

4. Assessment Parameters: Order No. 779, Paragraph 67

In Order No. 779, the Commission stated that each responsible entity under the Second Stage GMD Reliability Standards would "be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR and adopted in this Final Rule."[67] The proposed Reliability Standard requires applicable entities to perform assessments that will identify the impacts from the Benchmark GMD Event on the interconnected transmission system. The five assessment parameters are addressed as follows:

a) Parameter No. 1: The Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments.

Evaluation criteria are uniformly established in proposed Requirement R4, Table 1 – Steady State Planning Events, and Attachment 1 – Calculating Geoelectric Fields for the Benchmark GMD Event. Proposed Requirement R4 specifies system conditions. Table 1 establishes uniform performance criteria. Attachment 1 describes the procedure for calculating the Benchmark GMD Event for use in the GMD Vulnerability Assessment.

b) Parameter No. 2: The assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers, including the effects of GICs originating from and passing to other regions.

Proposed Requirements R4 and R6 address assessments of the effects of GICs on applicable transformers. Proposed Requirement R4 specifies that the responsible Planning Coordinators or Transmission Planners (as determined in Requirement R1) must conduct GMD Vulnerability Assessments that include steady state analysis to ensure transformer reactive losses

[67] Order No. 779 at P 67 (internal citation omitted).

from the Benchmark GMD Event do not produce voltage collapse, Cascading, and uncontrolled islanding. Proposed Requirement R6 specifies that applicable Transmission Owners and Generator Owners must conduct thermal impact assessments of applicable power transformers. Proposed Requirement R4 Part R4.3 provides for information-sharing so that the effects of GICs in other planning areas are factored into GMD Vulnerability Assessments. Specifically, proposed Requirement R4 Part 4.3 specifies that GMD Vulnerability Assessments must be provided to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability related need.

c) Parameter No. 3: The assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues.

In addition to assessing heating and reactive power effects in transformers, proposed Requirements R4 and Table 1 – Steady State Planning Events address assessments of the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the loss of devices due to GIC impacts. The study or studies conducted by the applicable Planning Coordinators and Transmission Planners in complying with Requirement R4 must evaluate the performance of the System during a Benchmark GMD Event to prevent voltage collapse, Cascading, and uncontrolled islanding. Devices that Planning Coordinators and Transmission Planners anticipate may be susceptible to harmonic impacts as a result of GIC are to be removed from the System in the analysis, since these devices may affect System performance. Thus, the GMD Vulnerability Assessment includes the effects caused by GIC on the reliable operation of the Bulk-Power System.

d) Parameter No. 4: In conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed. A severe GMD event can cause simultaneous stresses at multiple locations on the Bulk-Power System, potentially resulting in a multiple-outage event. In predicting GIC flows, it is necessary to take into consideration the network topology as an integrated whole (i.e., on a wide-area basis).

Proposed Reliability Standard TPL-007-1 accounts for wide-area impacts by requiring information exchange and involving appropriate entities. Proposed Requirement R4 and Requirement R7 specify that GMD Vulnerability Assessments and Corrective Action Plans must be provided to Reliability Coordinators, adjacent Planning Coordinators and Transmission Planners, and the functional entities specifically referenced in the plans. Reliability Coordinators work together to maintain real-time reliable operations in the wide area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator area will support this function. Planning Coordinators integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model.[68]

e) Parameter No. 5: The assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.

Proposed Reliability Standard TPL-007-1 requires GMD Vulnerability Assessments to be periodically updated, not to exceed every 60 calendar months from the preceding GMD

[68] NERC, *Reliability Functional Model Technical Document* v. 5 (Dec. 2009) at 10-11, *available at* http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/FM_Technical_Document_V5_2009Dec1.pdf.

Vulnerability Assessment. The periodicity was established with consideration to the high-impact, low-frequency nature of the Benchmark GMD Event.

5. Improvements in Scientific Understanding of GMDs: Order No. 779, Paragraph 68

In Order No. 779, the Commission stated that NERC should consider "developing Reliability Standards that can incorporate improvements in the scientific understanding of GMDs."[69] NERC considered and addressed the Commission's concerns.

The Requirements in proposed Reliability Standard TPL-007-1 are performance-based, which allows applicable entities to use state of the art tools and methods to accomplish the specified reliability objectives. The standard does not contain prescriptive requirements for applicable entities to use specific tools, models, or procedures which would limit the applicability of improvements in scientific understanding. Furthermore, the use of modern magnetometer data and statistical methods in determining the Benchmark GMD Event supports reevaluation as additional magnetometer data are collected during future solar cycles.

6. Plans to Protect Against Instability, Uncontrolled Separation, or Cascading Failures of the Bulk-Power System: Order No. 779, Paragraph 79

In Order No. 779, the Commission directed NERC to submit for approval one or more Reliability Standards that, in the event potential impacts from a benchmark GMD event are identified:

> [R]equire owners and operators of the Bulk-Power System to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power

[69] Order No. 779 at P 68.

> System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event.[70]

This directive is addressed by proposed Requirement R7 of proposed Reliability Standard TPL-007-1. An entity must develop a Corrective Action Plan in the event its System fails to meet specified performance criteria. Proposed Requirement 7 Part 7.1 lists acceptable actions, which are not limited to considering Operating Procedures or enhanced training.

7. Performance of Vulnerability Assessments and Developing Plans to Mitigate Identified Vulnerabilities: Order No. 779, Paragraph 82

In Order No. 779, the Commission stated, "As with the First Stage GMD Reliability Standards, the responsible entities should perform vulnerability assessments of their own systems and develop the plans for mitigating any identified vulnerabilities."[71] As discussed above, the proposed standard requires applicable entities to conduct assessments on their systems and develop plans to mitigate identified vulnerabilities. In proposed Requirement R1, applicable Planning Coordinators and Transmission Planners identify responsibilities for maintaining models and performing studies needed for GMD Vulnerability Assessments, as specified in Requirement R4. In proposed Requirement R6, applicable Transmission Owners and Generator Owners are required to conduct thermal impact assessments of applicable BES power transformers and, if necessary, specify mitigating actions. Proposed Requirement R7 requires the responsible Planning Coordinator or Transmission Planner (as determined in Requirement R1) to develop a Corrective Action Plan in the event that it concludes, through the GMD Vulnerability Assessment, that its system does not meet performance requirements.

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[70] Order No. 779 at P 79.

[71] Order No. 779 at P 82.

8. Strict Liability: Order No. 779, Paragraph 84

The Commission noted in Order No. 779 that the second stage Reliability Standards "should not impose 'strict liability' on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity, as some commenters fear."[72] In accordance with Order No. 779, proposed Reliability Standard TPL-007-1 establishes requirements for evaluating and mitigating the impacts of a Benchmark GMD Event on the reliable operation of the Bulk-Power System, but does not impose strict liability on responsible entities for failure to ensure reliable operation during a GMD event of unforeseen severity. Instead, the proposed Reliability Standard is designed to ensure the reliable operation of the Bulk-Power System in response to the identified Benchmark GMD Event. The identification of a robust and technically-justified Benchmark GMD Event in the Reliability Standard addresses the concern that responsible entities might otherwise be required to prevent instability, uncontrolled separation, or cascading failures of the Bulk-Power System when confronted with GMD events of unforeseen severity.

9. Automatic Blocking Measures: Order No. 779, Paragraph 85

In Order No. 779, the Commission stated that it would not require the use of automatic blocking measures in the second stage GMD Reliability Standards. The Commission stated, "given that some responsible entities have or may choose automatic blocking measures, the

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[72] Order No. 779 at P 84.

NERC standards development process should consider how to verify that selected blocking measures are effective and consistent with the reliable operation of the Bulk-Power System."[73]

The GMD Vulnerability Assessment process considers all mitigation measures in modeling, assessment, and mitigation requirements. Proposed Requirement R2 specifies that the responsible entity (i.e. the Planning Coordinator or Transmission Planner(s), as determined in Requirement R1) shall maintain system models for performing GMD Vulnerability Assessments, which will include automatic blocking measures that are part of the system as described in the technical guidance.[74] The responsible entity must perform studies based on these models, as required in proposed Requirement R4, to verify effectiveness and the reliable operation of the Bulk-Power System. When an applicable Transmission Owner or Generator Owner (R6) or responsible Planning Coordinator or Transmission Planner (R7) identifies a need for mitigation actions such as blocking measures, proposed Requirements R6 and R7 specify that information must be shared with planning entities. A planning entity is in the best position to identify whether selected mitigation actions are effective to address the GMD impacts identified in the GMD Vulnerability Assessment and are consistent with the reliable operation of its System. In this way, the standards development process has addressed evaluation of automatic blocking measure effectiveness on the reliable operation of the Bulk-Power System.

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10. Reliability Goals: Order No. 779, Paragraph 86

In Order No. 779, the Commission stated that "the NERC standards development process should consider how the reliability goals of the proposed Reliability Standards can be achieved

[73] Order No. 779 at P 85.

[74] *See generally* GIC Application Guide.

by a combination of automatic measures including, for example, some combination of blocking, improved "withstand" capability, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit."[75]

This suggestion is addressed by proposed Requirement R7 of proposed Reliability Standard TPL-007-1. When a responsible Planning Coordinator or Transmission Planner concludes through the GMD Vulnerability Assessment that its System does not meet performance requirements, it is required to develop a Corrective Action Plan. The plan must list deficiencies and the associated actions needed to achieve required performance. Proposed Requirement R7 provides examples of such actions, including installation or modification of equipment, use of Operating Procedures, and other actions specified in the Requirement.

11. Implementation Plan: Order No. 779, Paragraph 91

In Order No. 779, the Commission specified a number of considerations for NERC in developing an implementation plan for the second stage GMD Reliability Standard. The Commission stated:

> As stated in the NOPR, in a proposed implementation plan, we expect that NERC will consider a multi-phased approach that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable operation of the Bulk-Power System are protected first. We also expect, as discussed above, that the implementation plan will take into account the availability of validated tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments.[76]

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[75] Order No. 779 at P 86.

[76] Order No. 779 at P 91.

NERC's implementation for proposed Reliability Standard TPL-007-1 is included as **Exhibit B** to this petition. As described above, the proposed implementation plan provides a multi-phased approach to implementation over a five-year period.

Phased implementation will provide the necessary time for applicable entities to develop the required models and for proper sequencing of system and equipment assessments performed by various applicable entities to build an overall assessment of GMD vulnerability. The proposed implementation plan takes into account the availability of validated tools, models, and data that are necessary to perform GMD Vulnerability Assessments.

Additionally, phased implementation will provide the necessary time for the development of viable Corrective Action Plans, which may require entities to develop, perform, or validate new or modified studies, assessments, and procedures to meet the TPL-007-1 requirements. Some mitigation measures may have significant budgeting, siting, or construction planning requirements.

GMD Vulnerability Assessment results are necessary to identify components that are vital to reliable operation during a benchmark GMD event. Therefore, a phased implementation approach will provide an appropriate time period for applicable entities to develop Corrective Action Plans that address identified impacts in a prioritized manner.

H. Enforceability of Proposed Reliability Standard TPL-007-1

The proposed Reliability Standard includes Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and

VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit G**.

The proposed Reliability Standard also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[77]

[77] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

V. <u>CONCLUSION</u>

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Definition;
- the proposed Reliability Standard in **Exhibit A**;
- the other associated elements in the Reliability Standard in **Exhibit A**, including the VRFs and VSLs (**Exhibits A and G)**; and
- the implementation plan, included in **Exhibit B**.

Respectfully submitted,

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Date: January 21, 2014

Exhibit A

Proposed Reliability Standard, TPL-007-1-Geomagnetic Disturbance Operations

A. Introduction

1. **Title:** **Transmission System Planned Performance for Geomagnetic Disturbance Events**
2. **Number:** TPL-007-1
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.
   4.2. Facilities:
   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. **Background:**
   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.
6. **Effective Date:**
   See Implementation Plan for TPL-007-1

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s), in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s*). [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1*. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

R4. Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1. If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;
6.2. Document assumptions used in the analysis;
6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
6.4. 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, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \tag{2}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2– Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[2] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2) or Table 2, β is applied to the reference geoelectric field using equation (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[3] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

where *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

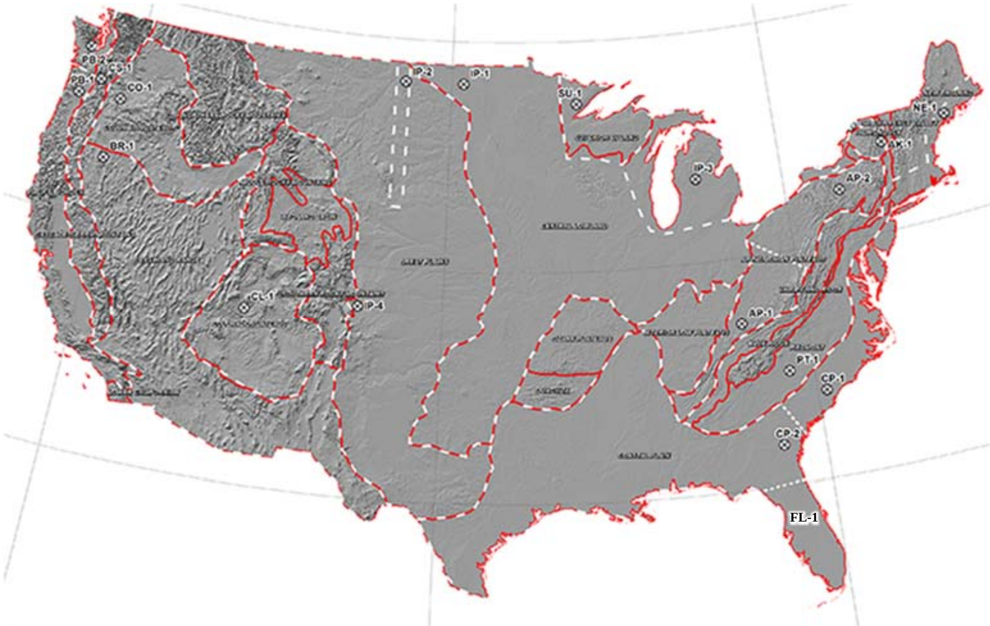


Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 – Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

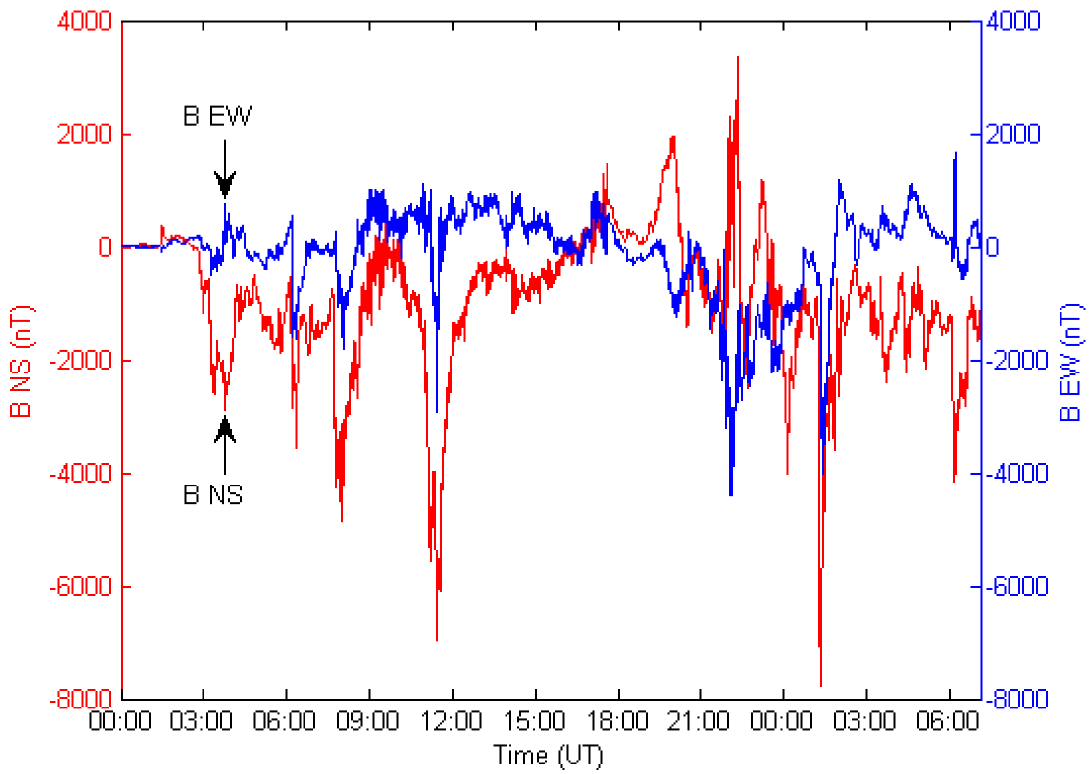


Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

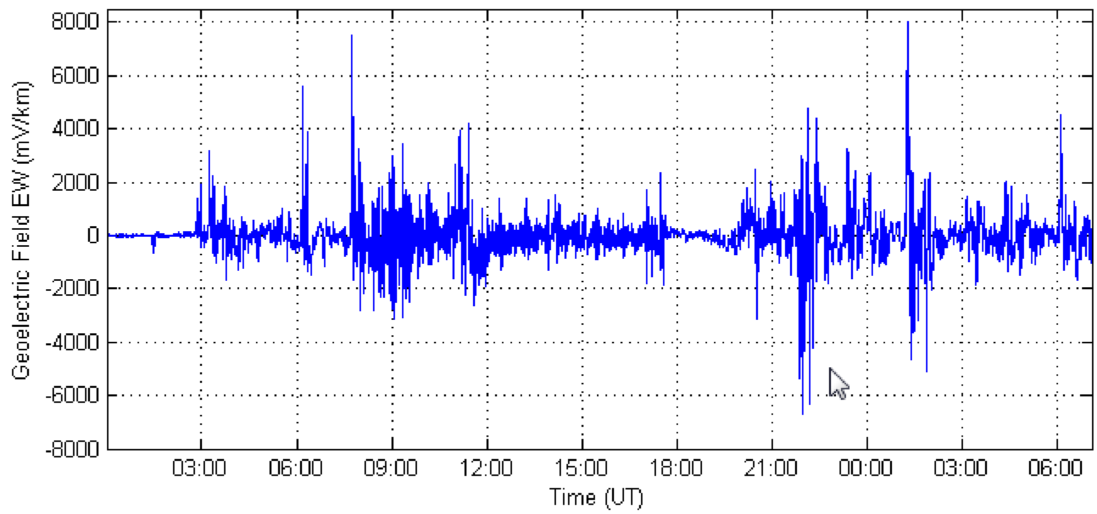


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

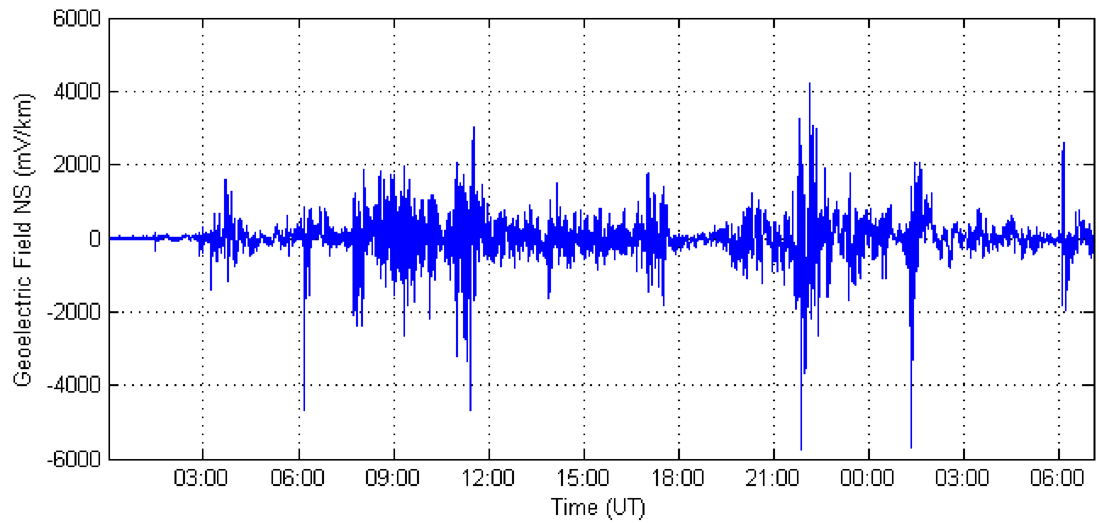


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.
The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

For Requirements R1, R2, R3, R5, and R6, each responsible entity shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible	The responsible entity did not maintain both System models and GIC System models of the responsible

					entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it

				was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R5	Long-term Planning	Medium	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar

			or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)
The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

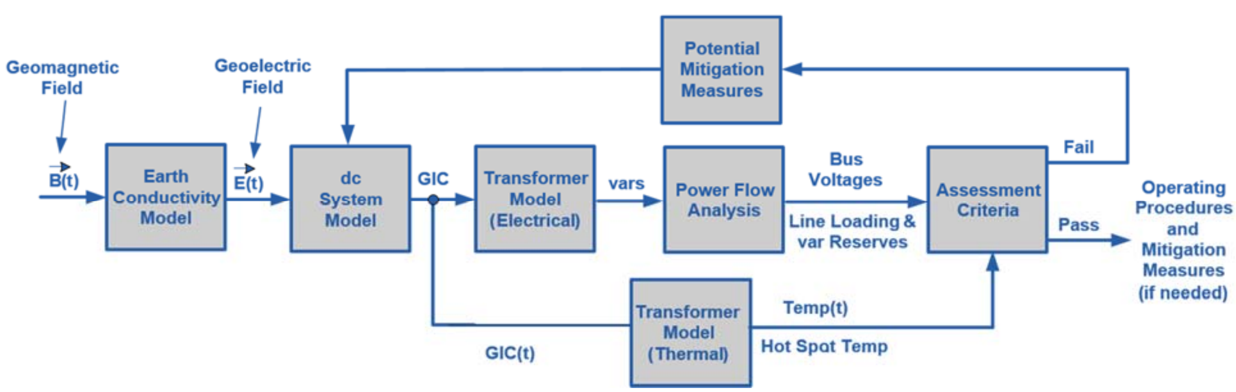
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4
The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page. http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:
The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase

Exhibit B

Implementation Plan for TPL-007-1

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required,

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Exhibit C

Order No. 672 Criteria for TPL-007-1

Exhibit C -- Order No. 672 Criteria

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

Proposed Reliability Standard TPL-007-1 addresses the unique risks posed by a high-impact, low-frequency GMD event on the reliable operation of the Bulk-Power System and is responsive to the Commission's concerns articulated in Order No. 779. The proposed standard requires applicable entities to conduct initial and on-going assessments of the potential impact of a benchmark GMD event on Bulk-Power System equipment and the Bulk-Power System as a whole and requires corrective action to protect against instability, uncontrolled separation, and cascading failures of the Bulk-Power System. The benchmark GMD event used to develop the

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

proposed standard is based on a 1-in-100 year frequency of occurrence, and is supported by rigorous technical analysis of modern measurement data and publicly-available models. Additional information regarding the benchmark GMD event is attached as **Exhibit D** to this petition.

Using a planning approach, the proposed Reliability Standard includes requirements for coordinating responsibilities among applicable entities, developing and maintaining models, establishing performance criteria and assessing performance, exchanging relevant information necessary to coordinate the actions of applicable entities, and developing Corrective Action Plans to address performance deficiencies.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard is applicable to: (1) Planning Coordinators with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (2) Transmission Planners with a planning area that includes a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; (3) Transmission Owners that own a Facility or Facilities that include a power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV; and (4) Generator Owners that own a Facility or Facilities that include a power transformer(s) with a high side, wye-

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

grounded winding with terminal voltage greater than 200 kV.[4] The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[5]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner.[6]

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These measures help provide clarity regarding how the Requirements will be enforced and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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[4] A power transformer with a "high side wye-grounded winding" refers to a power transformer with windings on the high voltage side that are connected in a wye configuration and have a grounded neutral connection.

[5] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

[6] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to conducting initial and on-going assessments of the potential impact of a benchmark GMD event on Bulk-Power System equipment and the Bulk-Power System as a whole and provides entities the flexibility to select appropriate mitigation strategies to address identified vulnerabilities.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant reliability benefits for the Bulk-Power System and addresses directives and concerns identified by the Commission in Order No. 779. The provisions of the proposed standard raise the level of preparedness by requiring applicable entities to plan for the reliable operation of the Bulk-Power

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[7] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

[8] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

System during a severe, 1-in-100 year GMD event. The proposed Reliability Standard and accompanying benchmark GMD event incorporate rigorous technical analysis that is representative of the complex nature of space weather phenomena and reflects a balanced and practical approach. Further, the proposed standard provides flexibility for entities to select appropriate mitigation strategies, subject to the vulnerabilities identified in the assessments and as supported by technical guidance.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[9]

The proposed Reliability Standard applies consistently throughout North America and does not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

Proposed Reliability Standard TPL-007-1 has no undue negative effect on competition and does not unreasonably restrict the available transmission capacity or limit the use of the Bulk-Power System in a preferential manner. The proposed standard requires the same

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[9] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

[10] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

performance by each of the applicable entities. The information sharing required by the proposed standard is necessary for reliability and can be accomplished without presenting any market or competition-related concerns.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The proposed effective date for proposed Reliability Standard TPL-007-1 and the proposed Definition of "Geomagnetic Disturbance Vulnerability Assessment" (or "GMD Vulnerability Assessment") is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes a multi-phase implementation plan over five years to allow applicable entities adequate time to ensure compliance with the Requirements. The proposed implementation plan is attached as **Exhibit B** to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability

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[11] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[12] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

Standards. **Exhibit I** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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[13] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[14] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

White Paper on GMD Benchmark Event Description

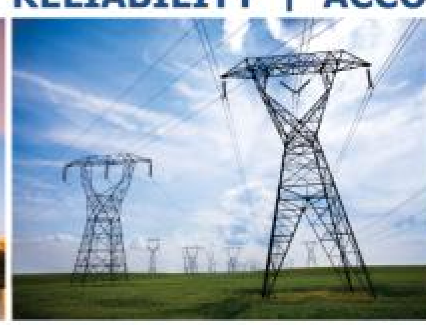
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
December 5, 2014

RELIABILITY | ACCOUNTABILITY



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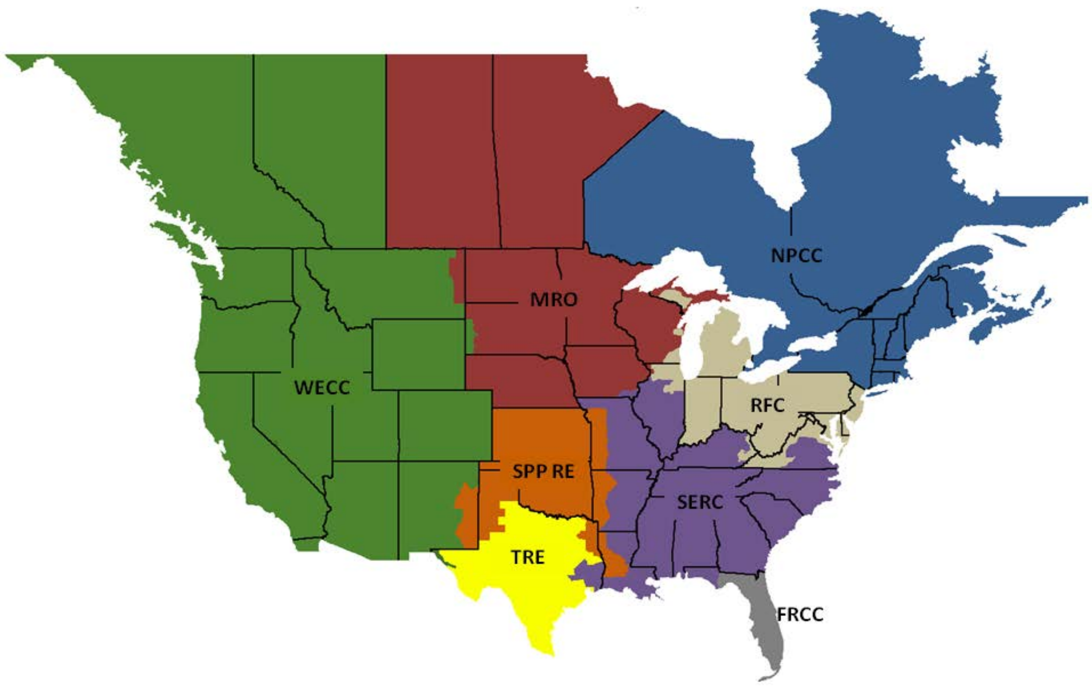
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the “Halloween event” of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

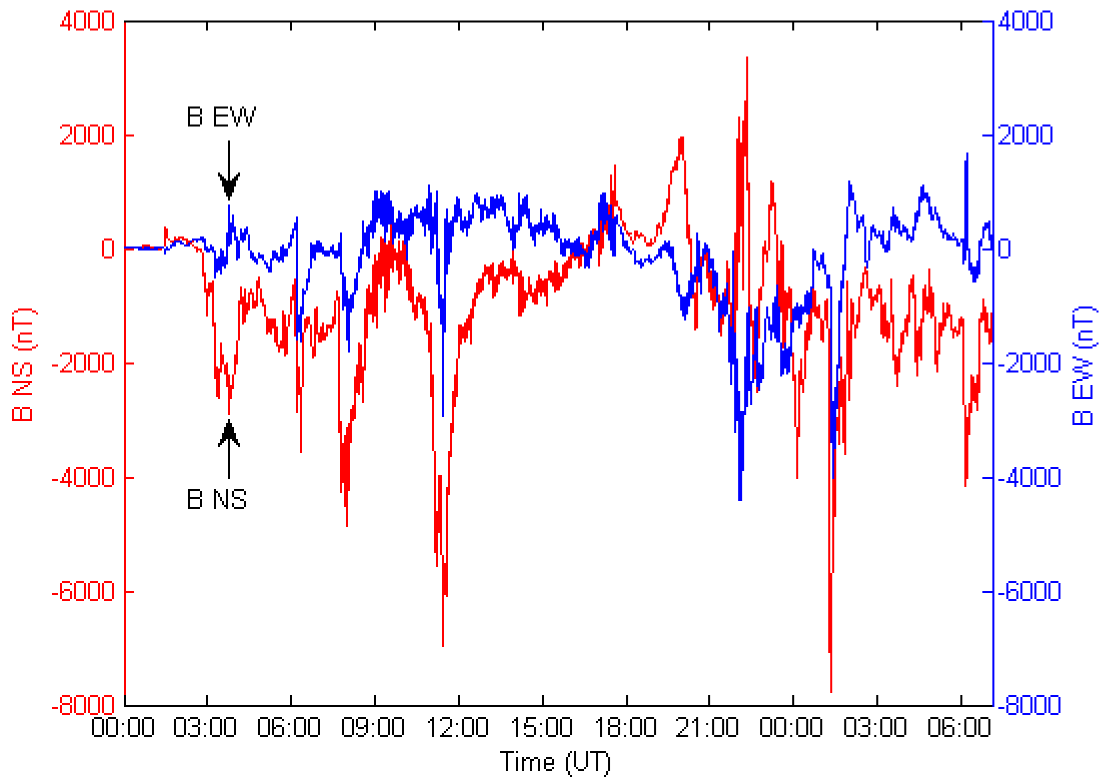


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

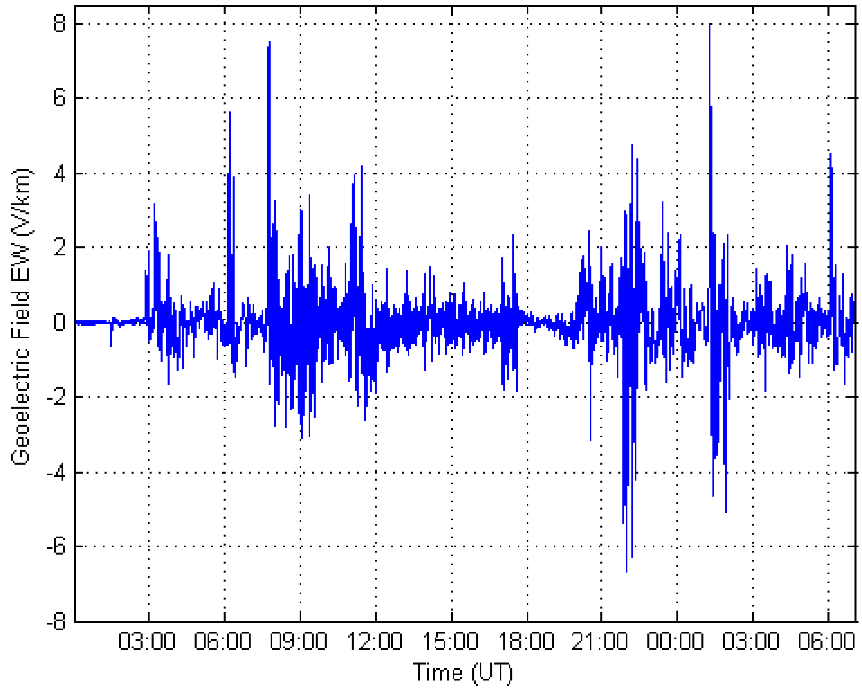


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

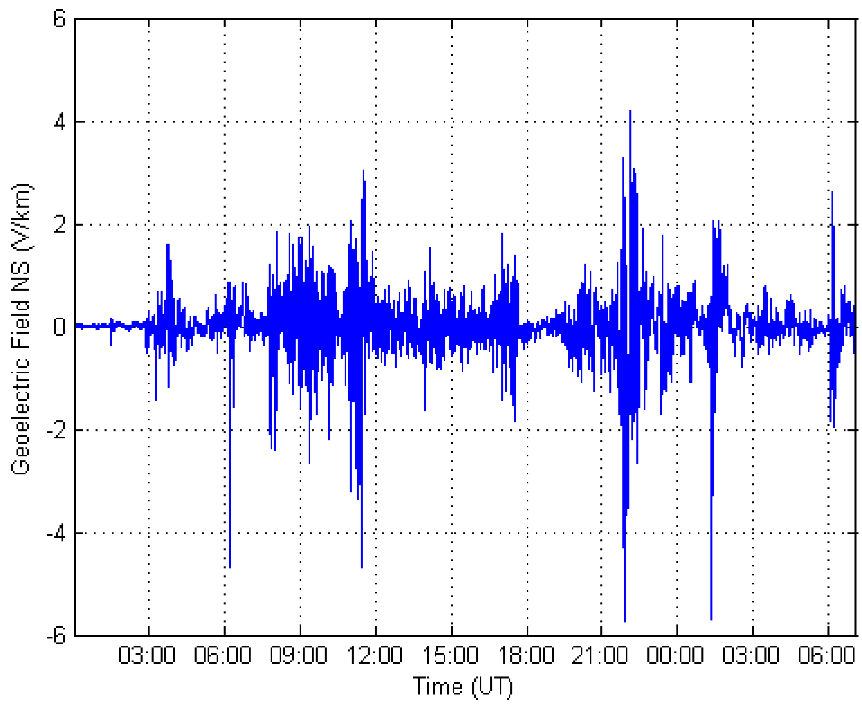


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

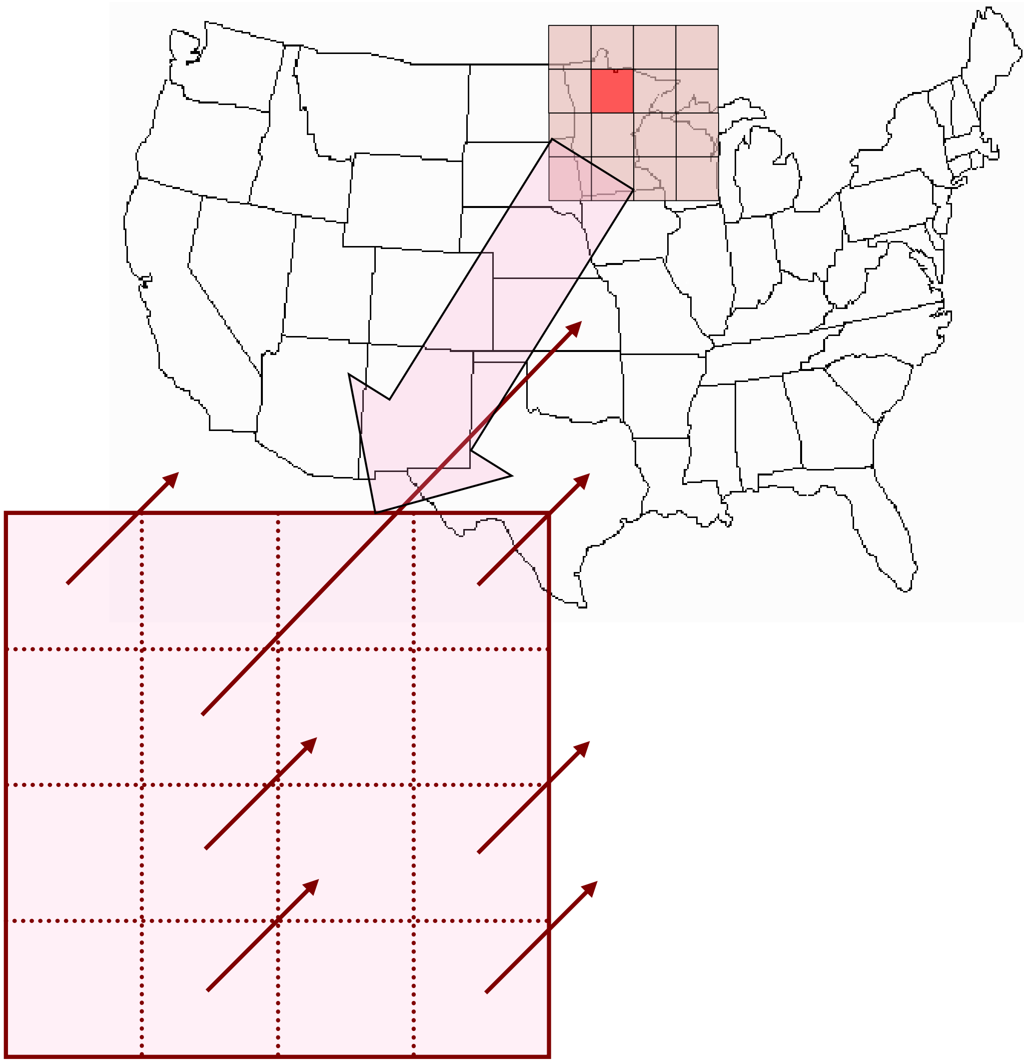


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

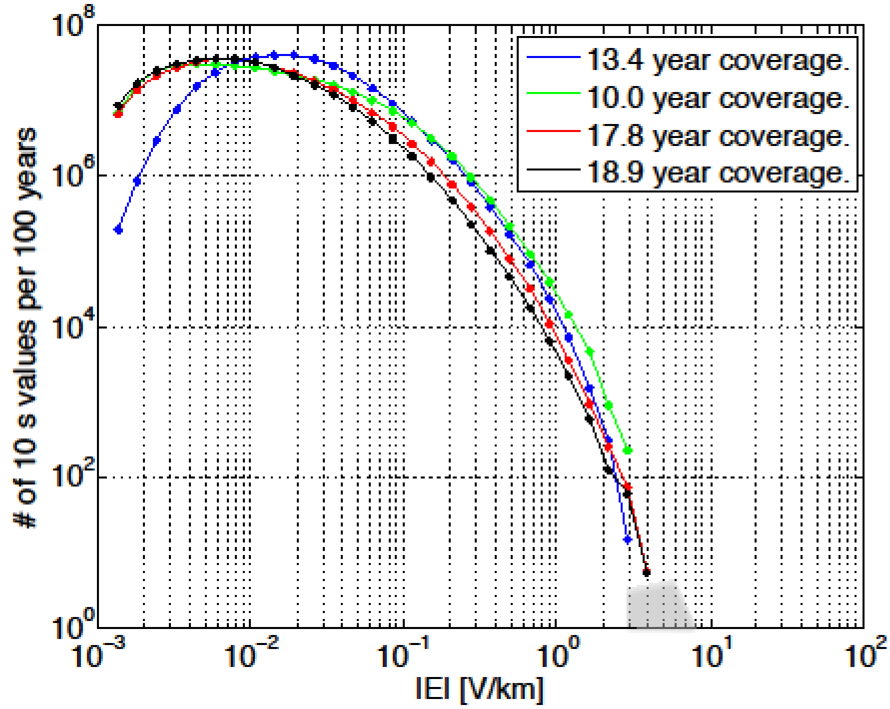


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

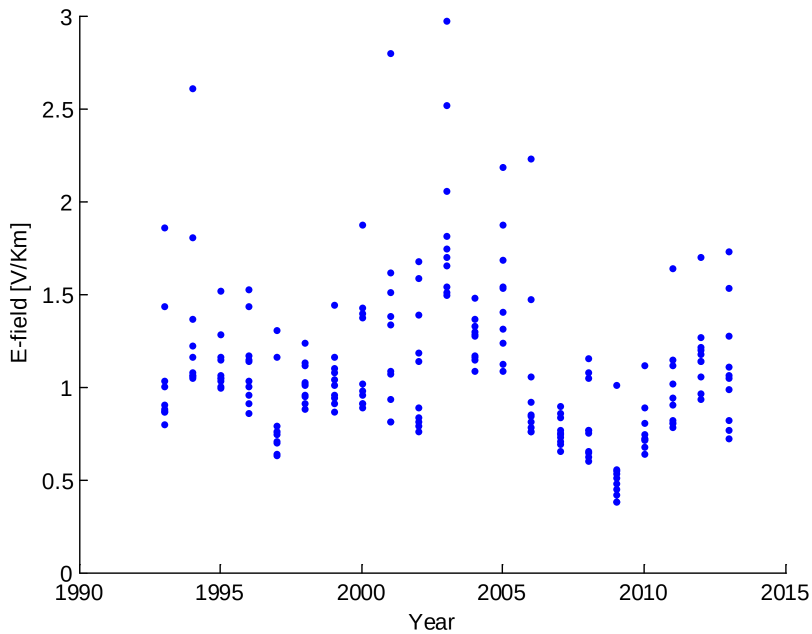


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	100 Year Return Level 95% CI [V/km]	100 Year Return Level 95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu=\beta_0+\beta_1\cdot\sin\left(\frac{t}{T}+\phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma=\alpha_0+\alpha_1\cdot\sin\left(\frac{t}{T}+\phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu=\beta_0+\beta_1\cdot\sin\left(\frac{t}{T}+\phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: α_1=0, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

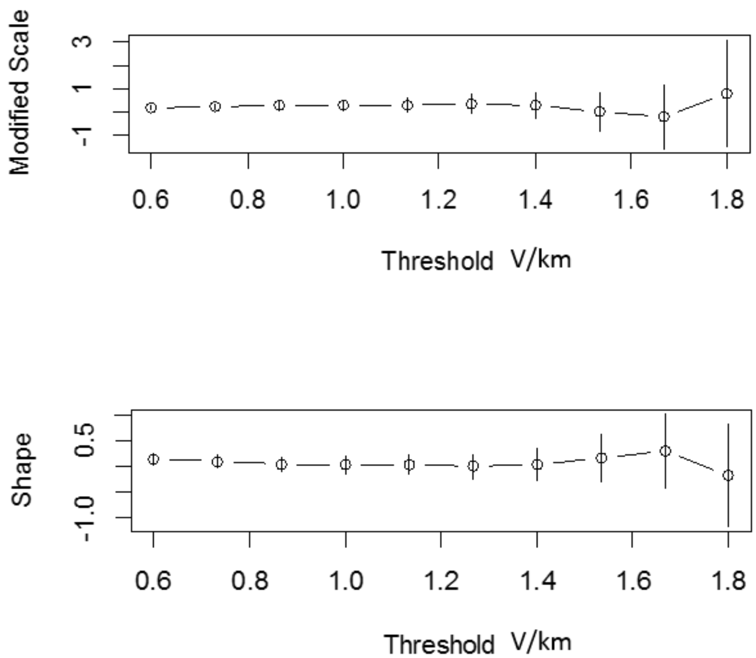


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

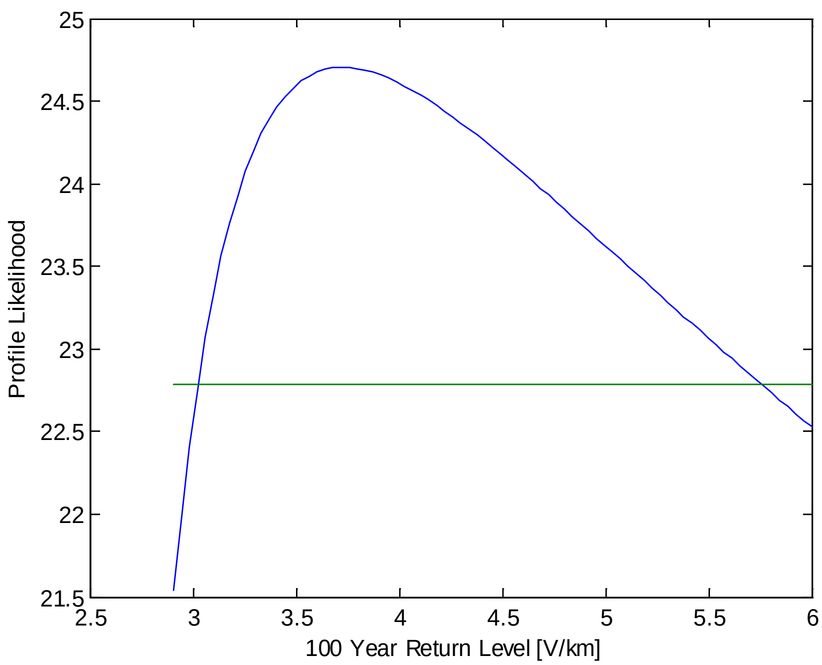


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

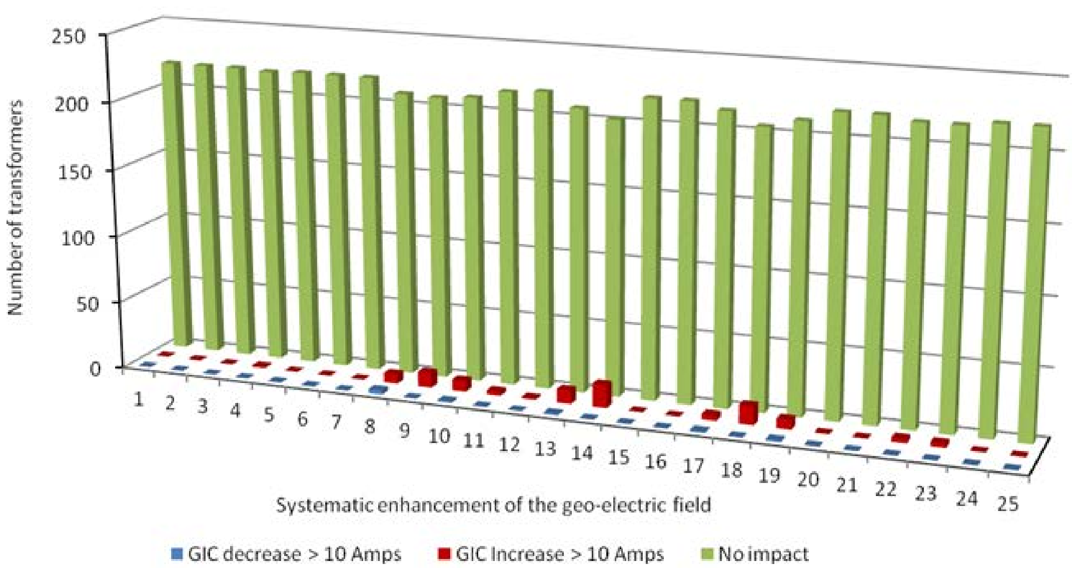


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

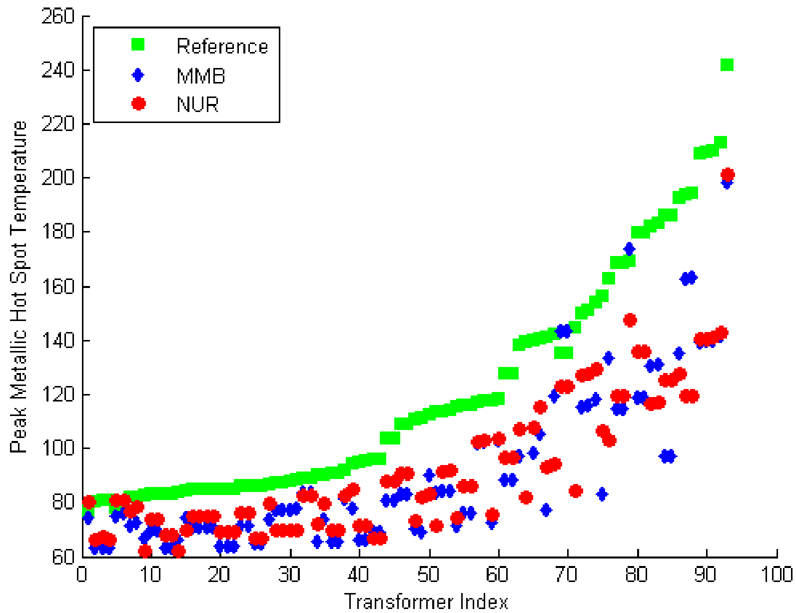


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

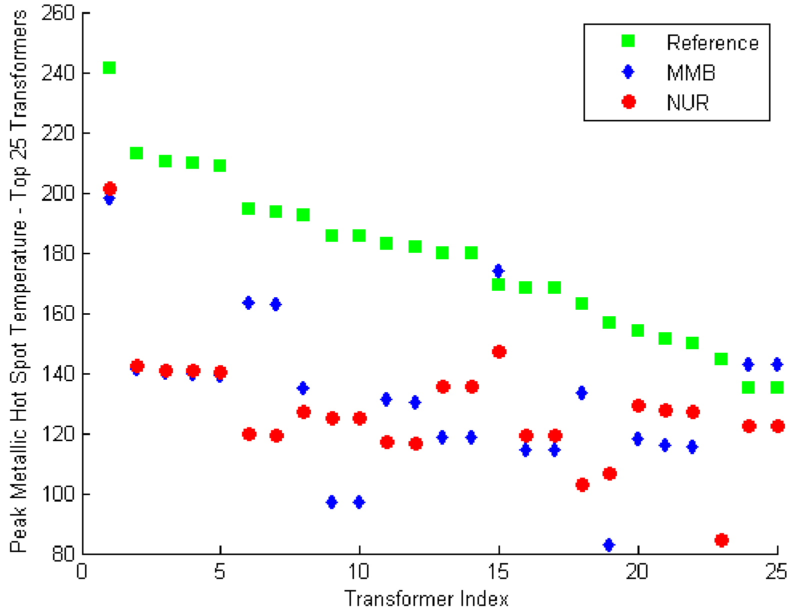


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

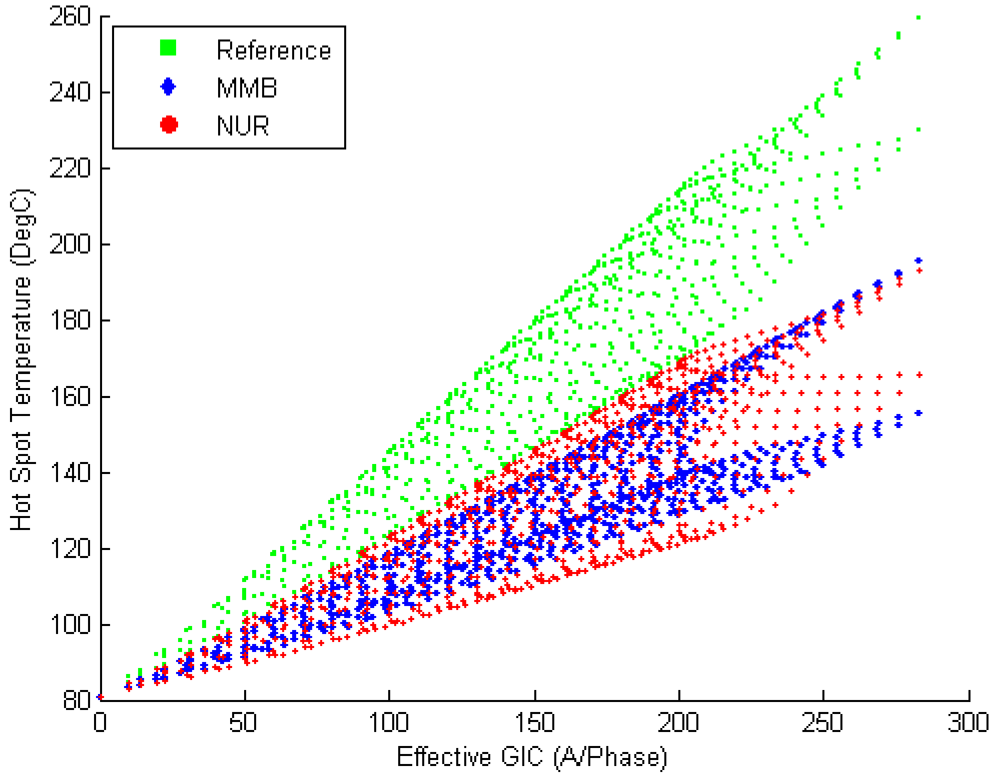


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \tag{II.1}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

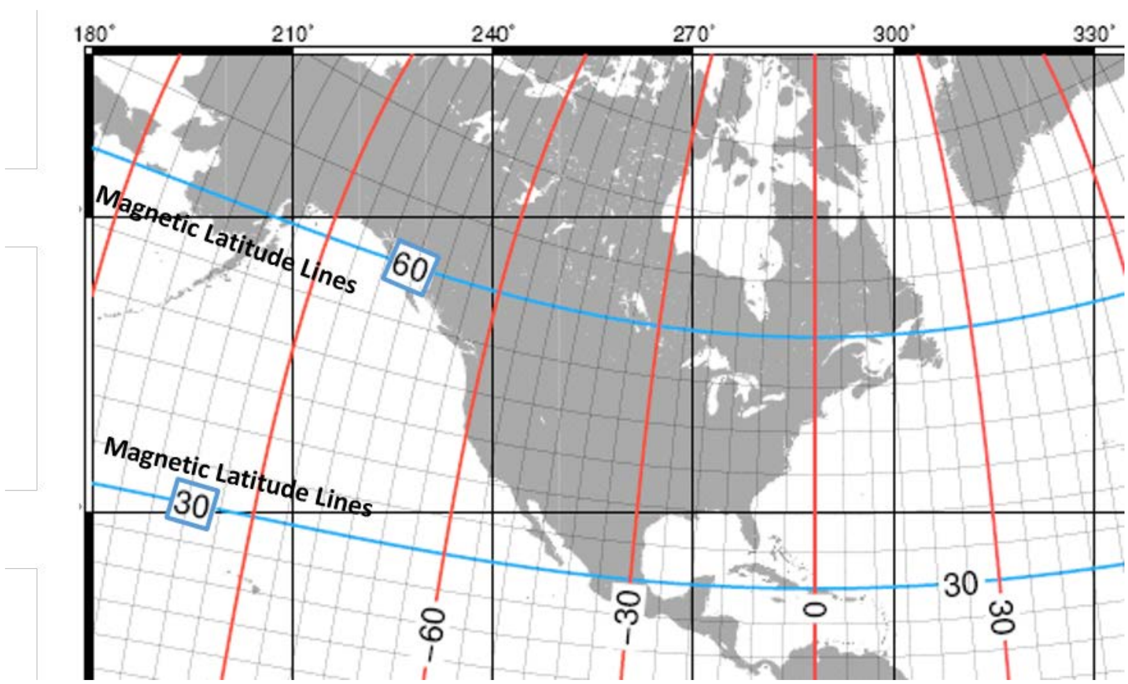


Figure II-1: Geomagnetic Latitude Lines in North America

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[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.
[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \tag{II.2}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

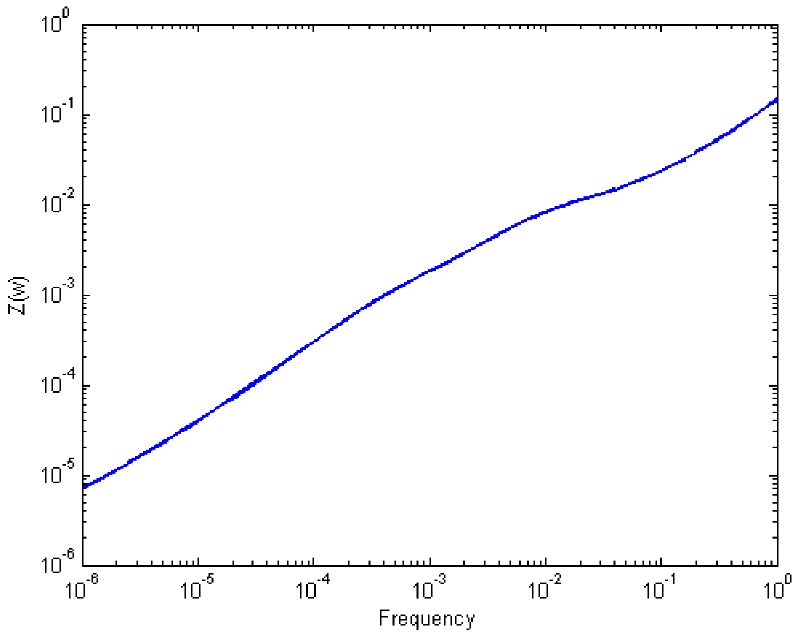


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

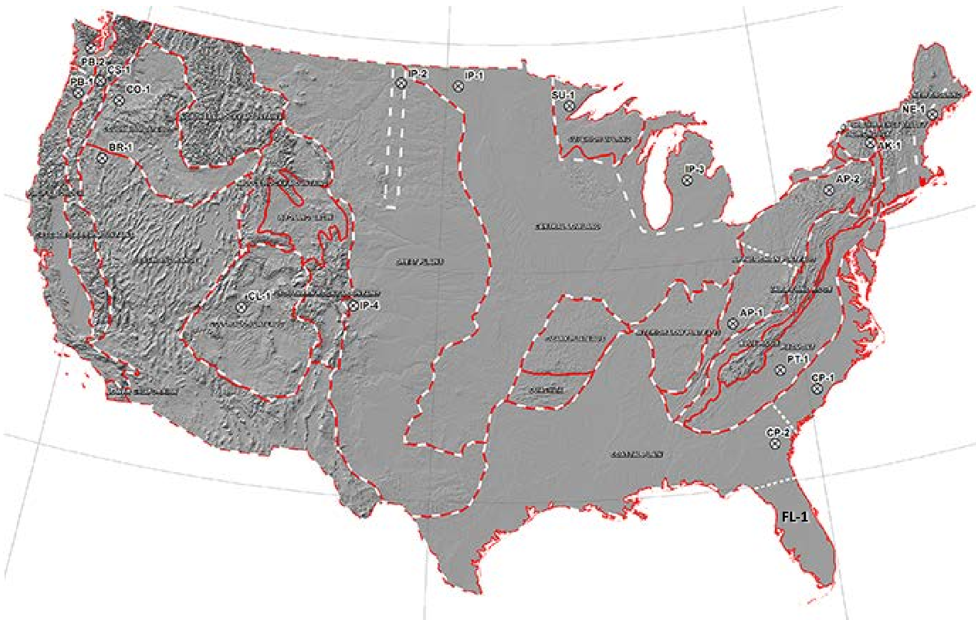
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use the largest β factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

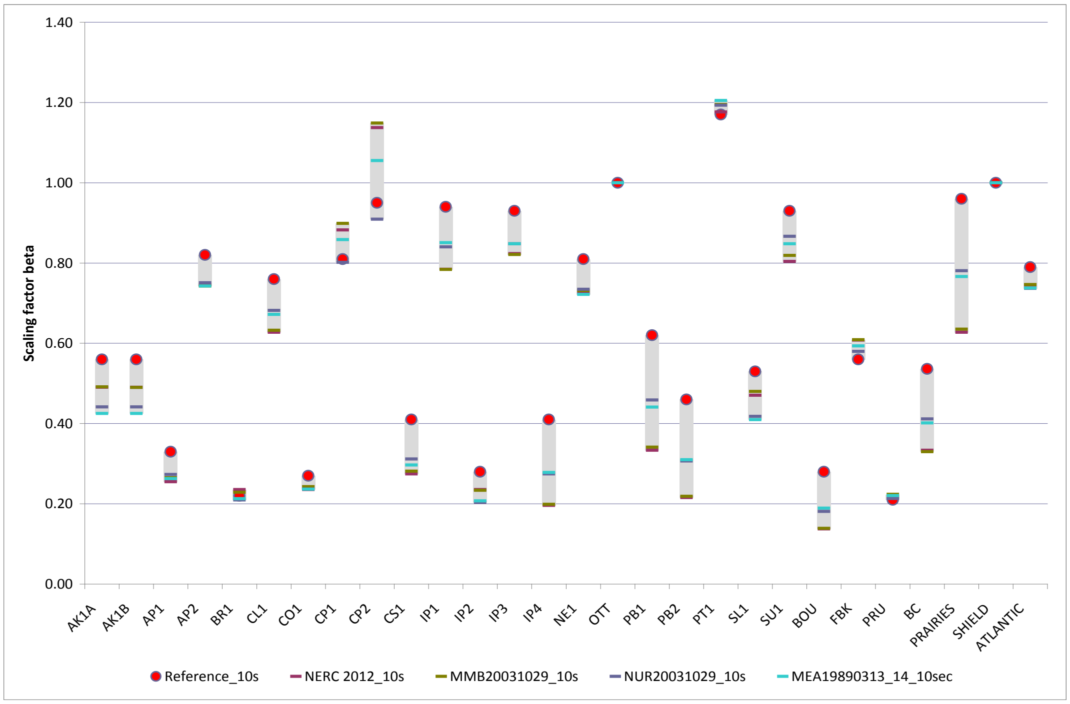


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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Exhibit E

White Paper on Transformer Thermal Impact Assessment

Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

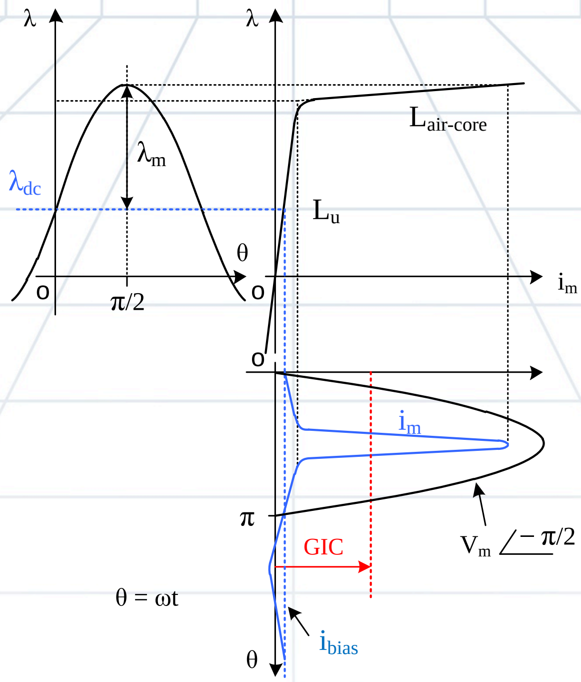

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or “waveshape” of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The “effective” GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \tag{1}$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as **Table 1** below, provides the peak metallic hot spot temperatures that can be reached using conservative screening thermal models. To use **Table 1**, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer

capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

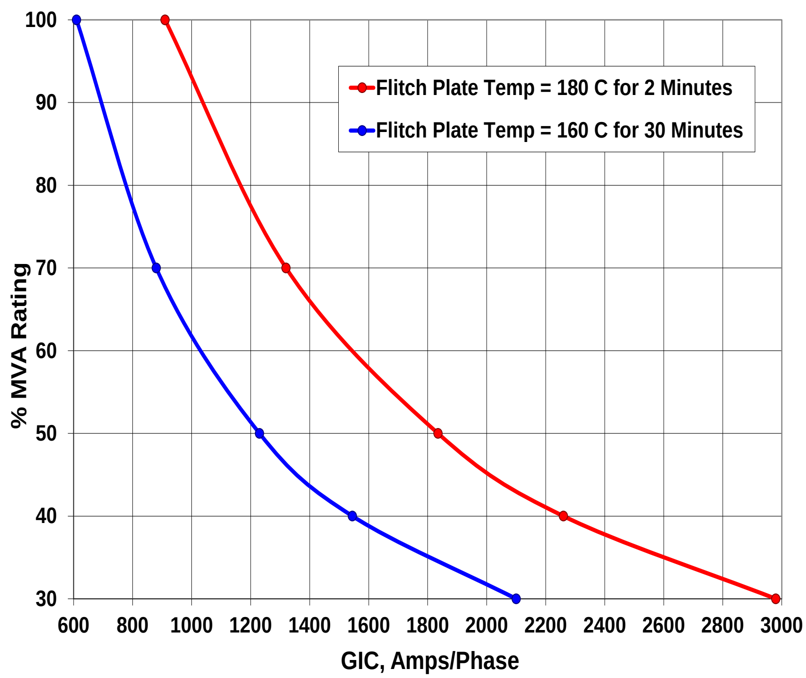

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. <u>Thermal response simulation</u>[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

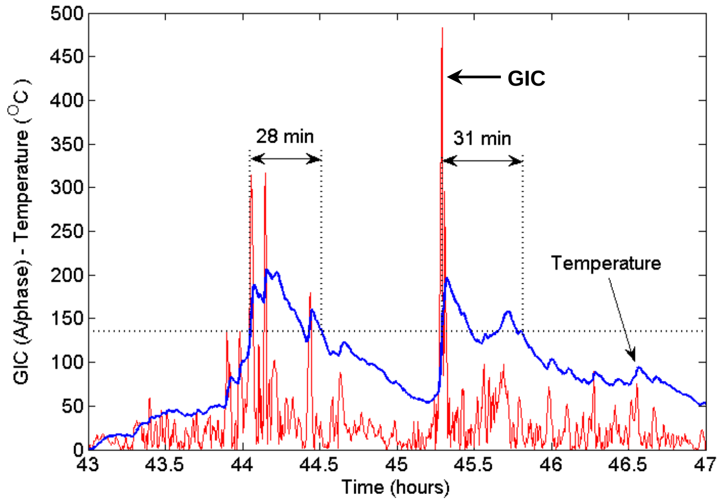

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

---

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

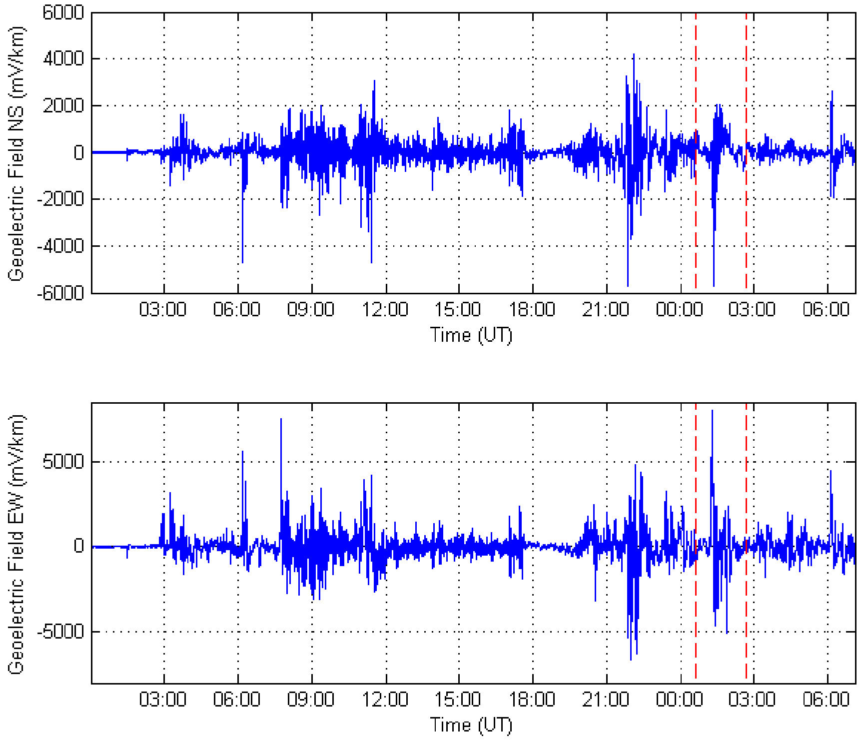

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

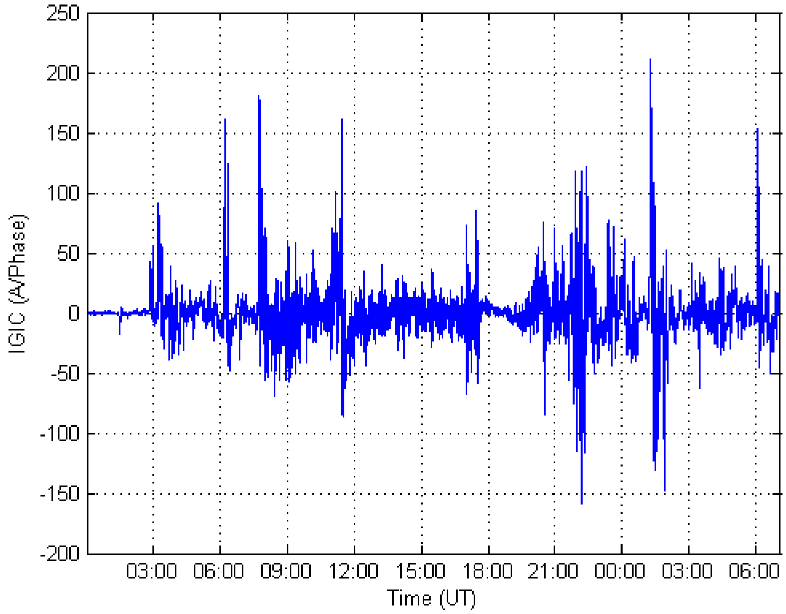

Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

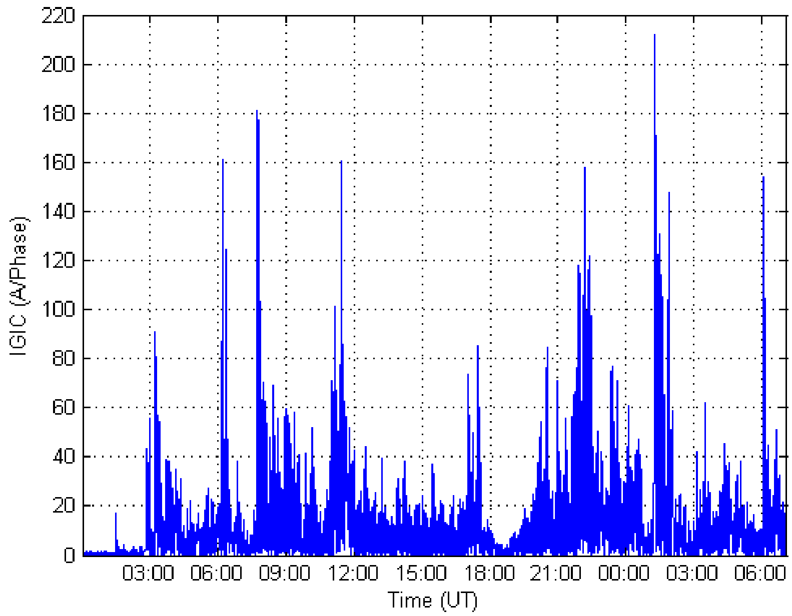

Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

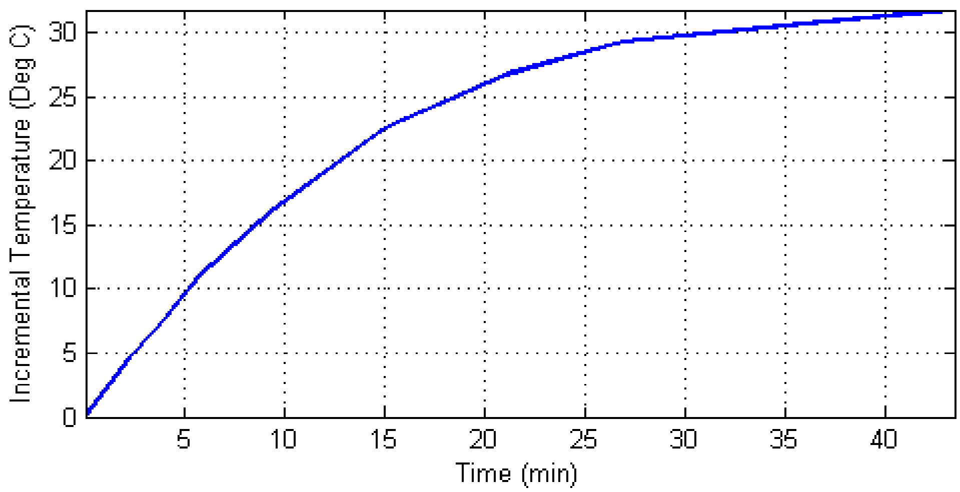

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

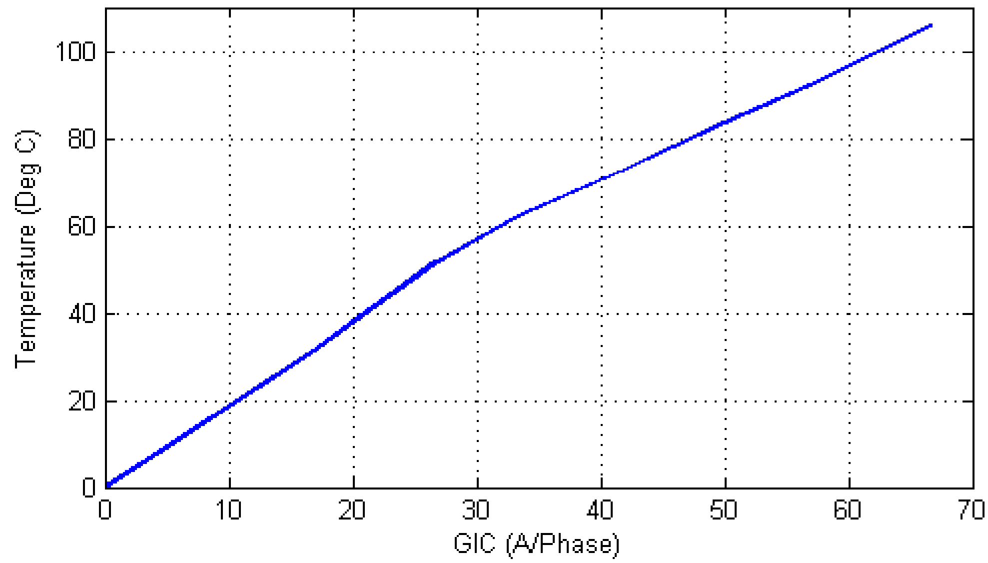

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

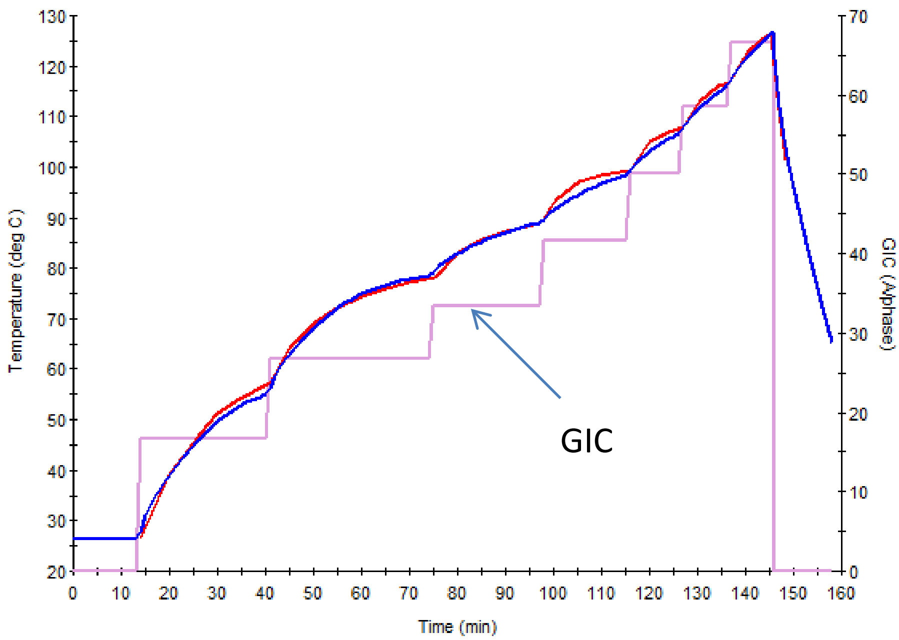

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time θ(t) for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

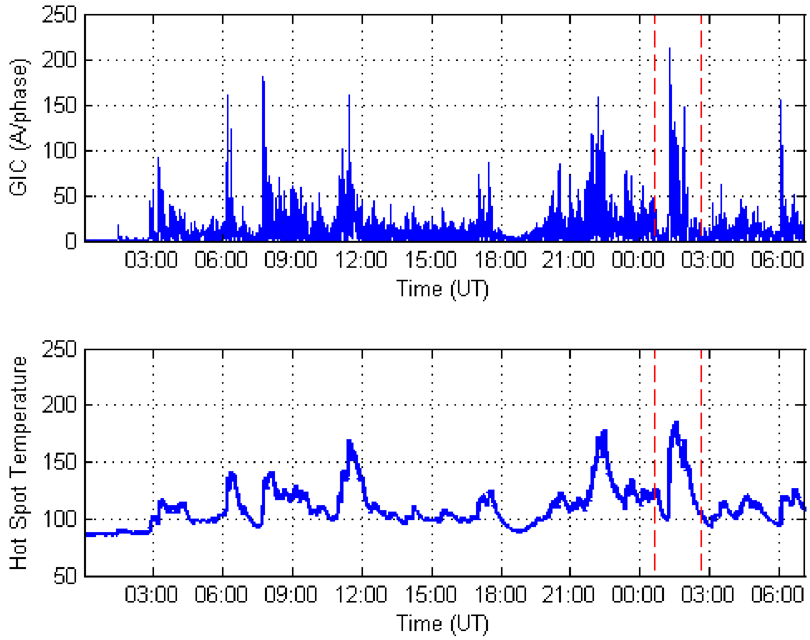

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

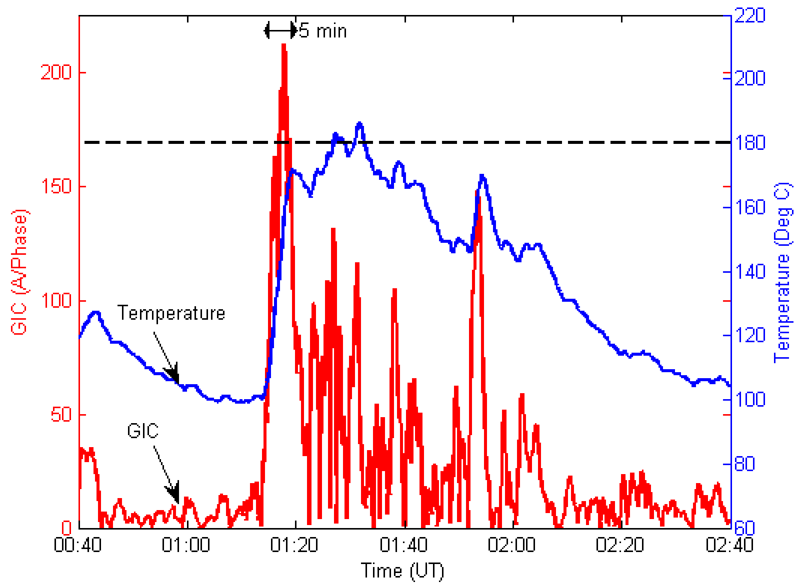

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

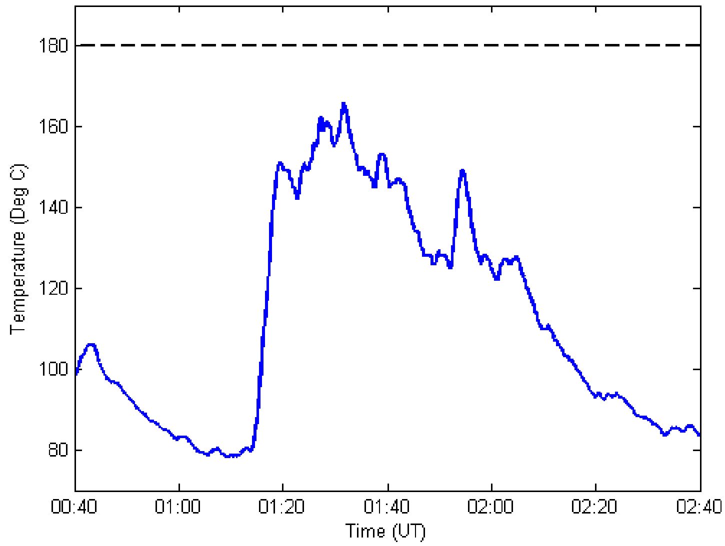

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std C57.91).

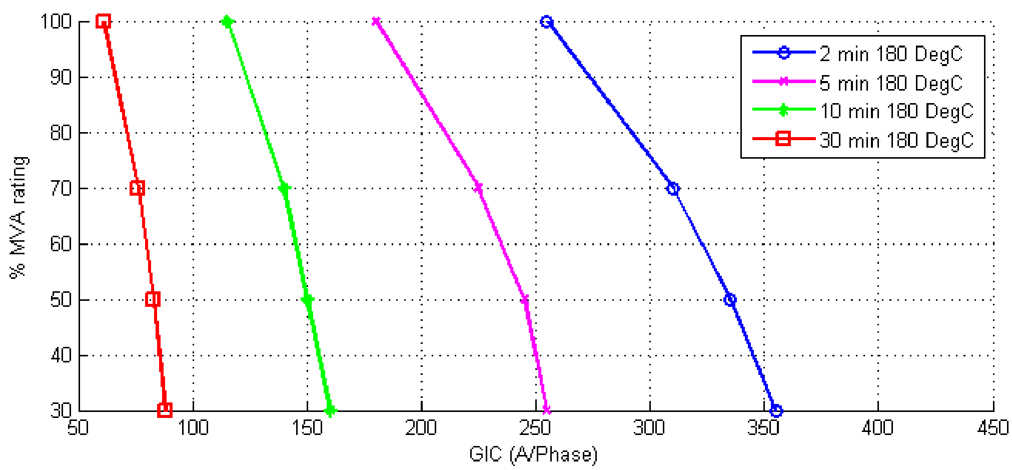

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

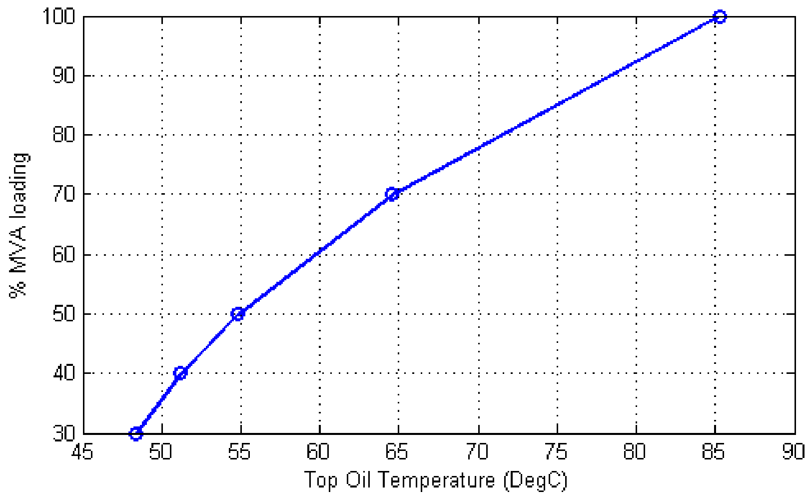

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

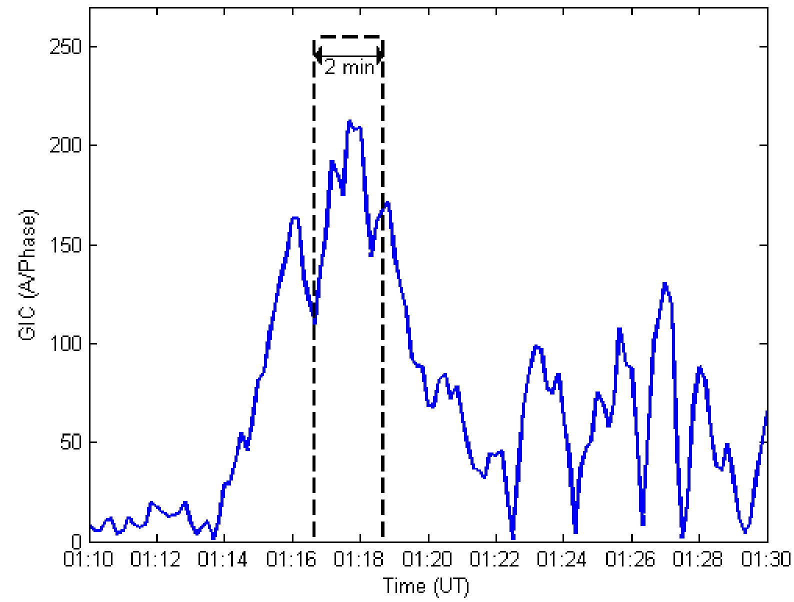

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

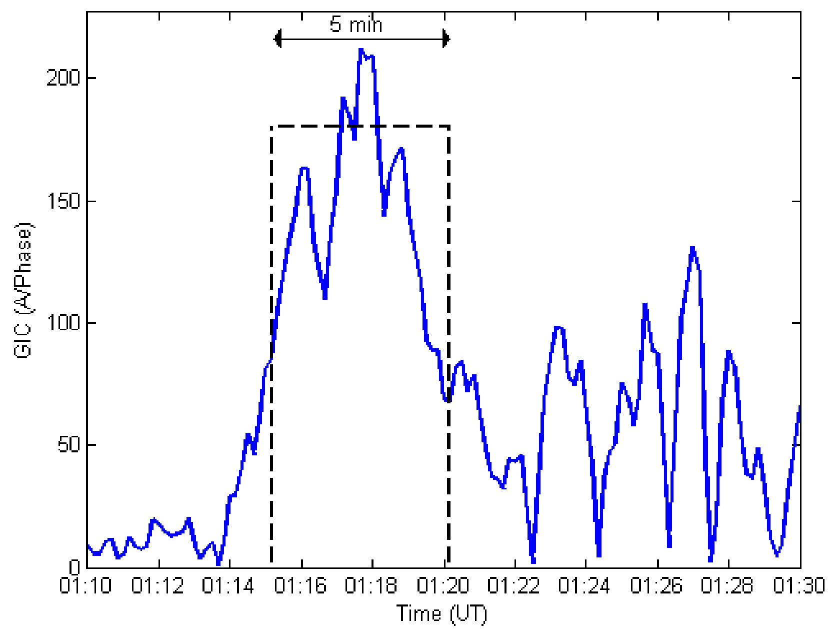

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

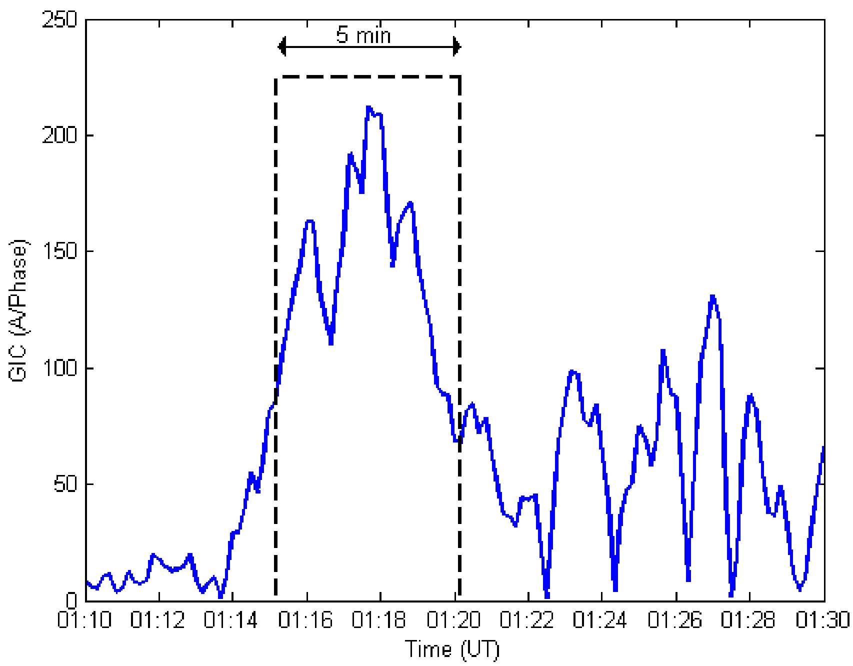

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

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[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

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[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

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http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Exhibit F

White Paper on Thermal Screening Criterion

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \qquad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (2)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (3)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (4)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**.

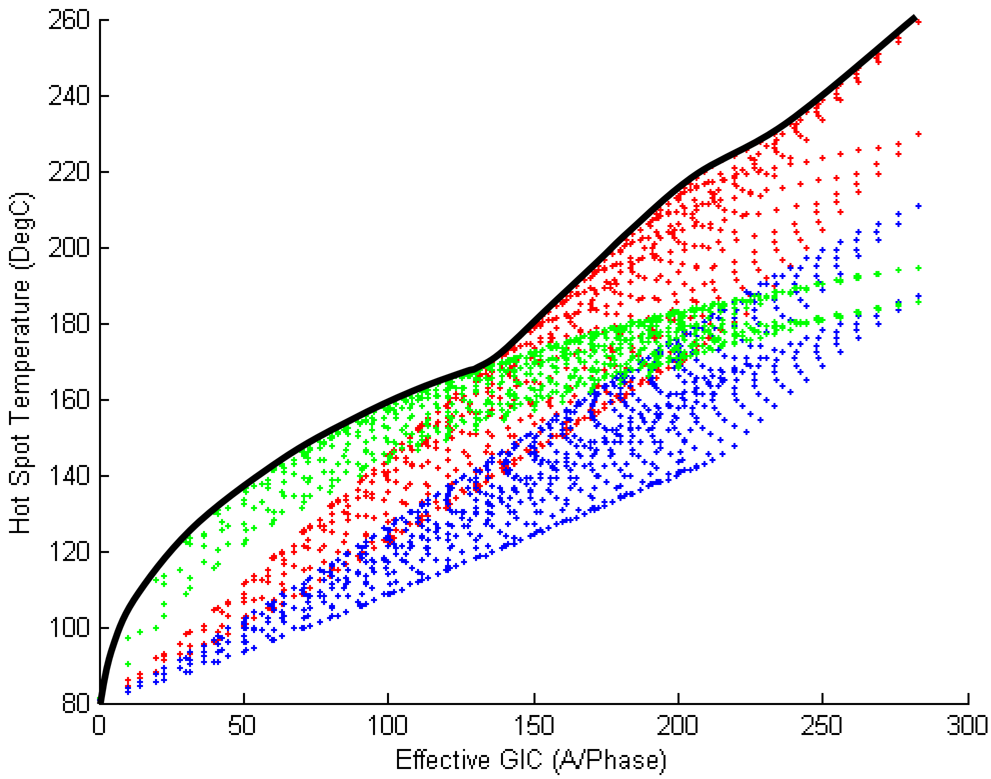

Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 104°C and 150°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 150°C falls well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 150°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the condition of specific transformers where IEEE Std C57.91-2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the screening model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a “pass” on the basis of the state of the knowledge at this point in time.
- The 75 A per phase screening threshold was determined on the basis of instantaneous peak hot spot temperatures. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.
- The models used in the determination of the threshold are conservative but technically justified.

- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

Appendix

The screening thermal model is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 2**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 3 and 4**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The third transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 5 and 6**). The asymptotic thermal behavior of this transformer shows a “down-turn” at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

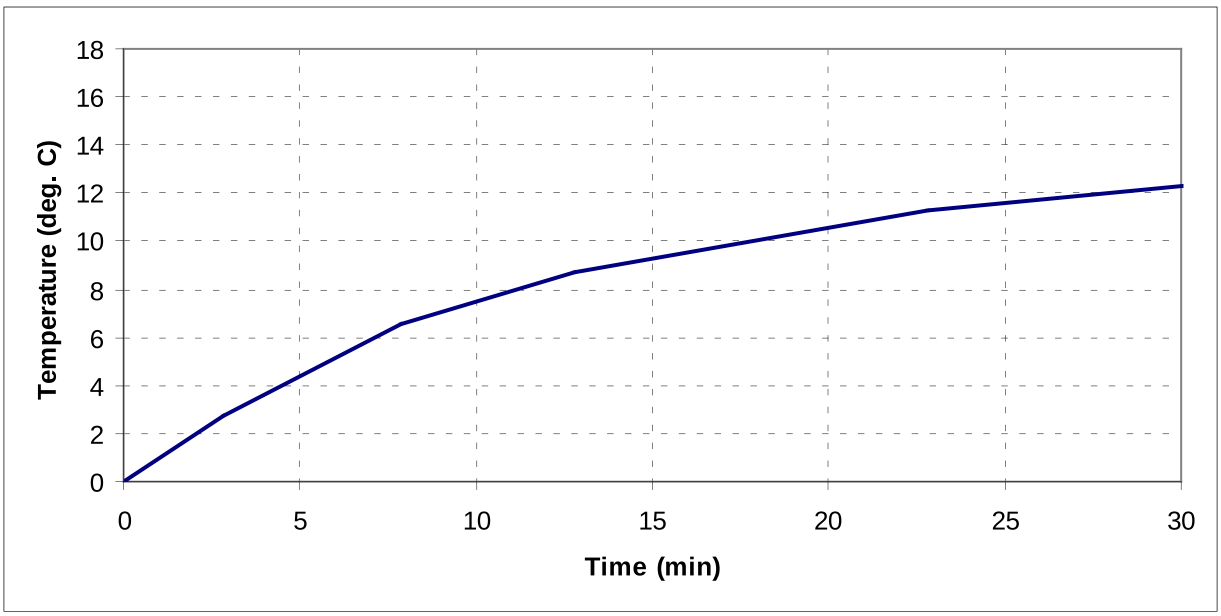

Figure 2: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

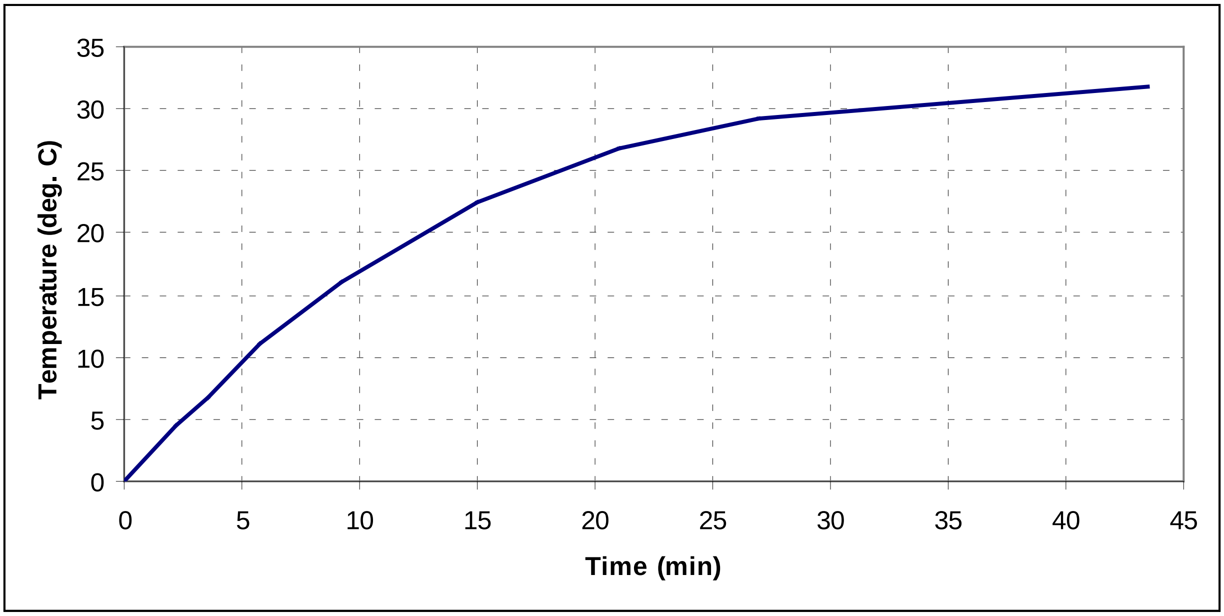

Figure 3: Step thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 10 A per phase dc step.

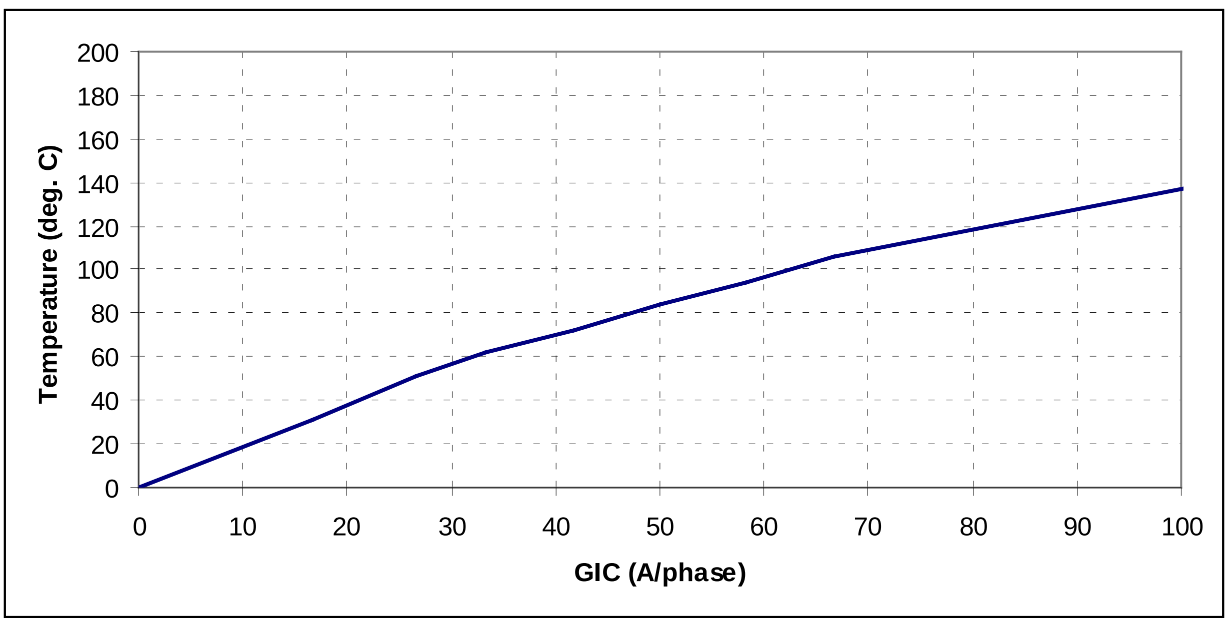

Figure 4: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

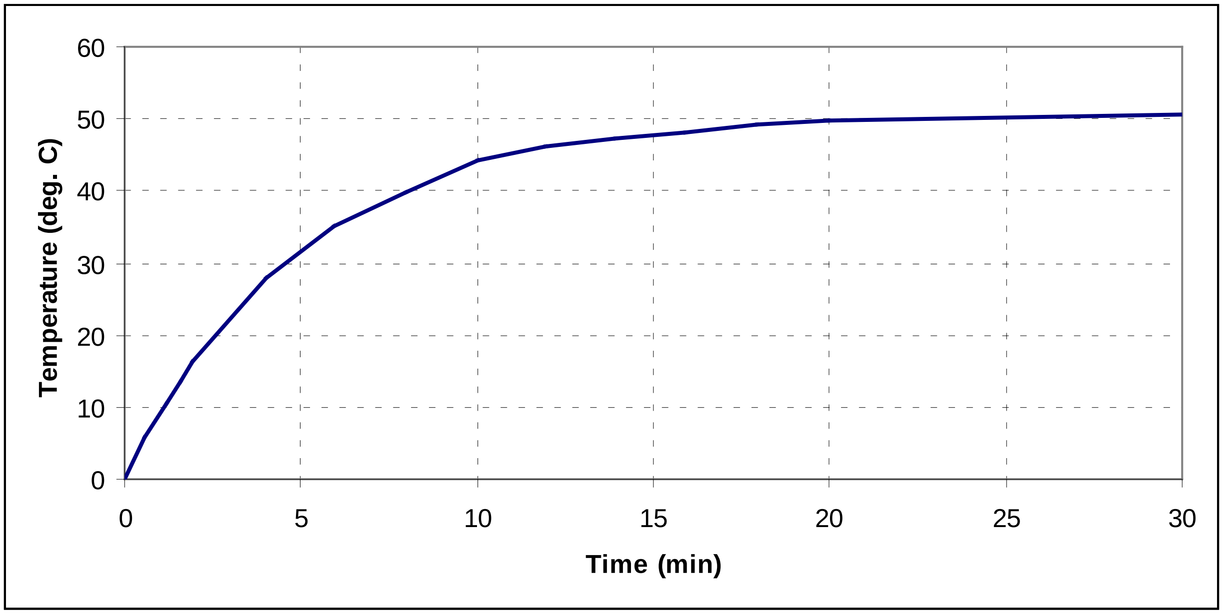

Figure 5: Step thermal response of tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

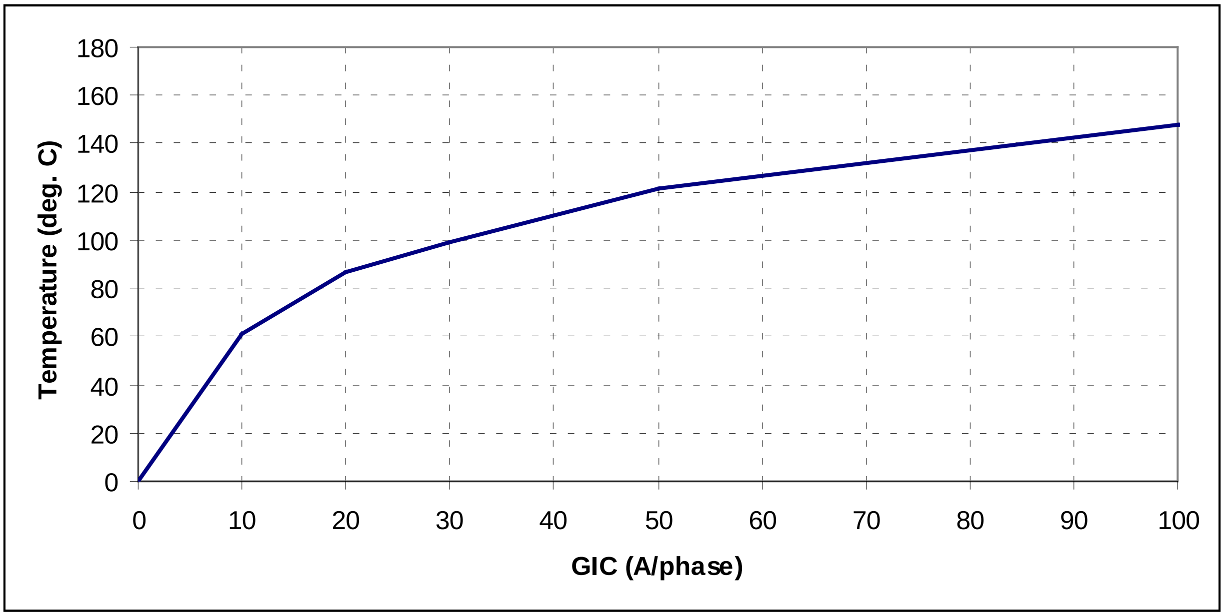

Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The composite envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event			
Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

For instance, if effective GIC is 150 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 180°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 59°C at maximum ambient temperature, then 210 A per phase of effective GIC translates in a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of GIC_E and GIC_N that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same screening model. For instance, the lower bound of peak temperatures for the screening model for 210 A per phase is 165°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[2] Marti, L., Rezaei-Zare, A., Narang, A., "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery,* vol.28, no.1, pp.320-327, Jan. 2013.

[3] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[4] J. Raith, S. Ausserhofer: "GIC Strength verification of Power Transformers in a High Voltage Laboratory", GIC Workshop, Cape Town, April 2014

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

Exhibit G

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities

- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs corresponding to requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation per-day basis is the "default" for penalty calculations.

VRF Justifications – TPL-007-1, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Lower is consistent with approved TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-1 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Lower is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing GMD studies, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System under conditions of a GMD event.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its

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

VSL Justifications – TPL-007-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R7. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with the VRF for approved TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-1, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the GMD Vulnerability Assessment. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R2			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R2			
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to models for GMD Vulnerability Assessments. Approved TPL-001-4 Requirement R1 requires entities to maintain System models for Planning Assessments and has multiple subparts to form the basis for a graduated VRF. However, the System model for GMD Vulnerability Assessment will have most elements in common with the System model used for Planning Assessments in TPL-001-4. System models for GMD Vulnerability Assessment are distinguished primarily in that they account for reactive power losses due to GIC. Therefore, the subparts from approved TPL-001-4 Requirement R1 were not duplicated in proposed TPL-007-1 Requirement R2 and the VSL was not separated into further degrees of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R2	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-1 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during a benchmark GMD event; these criteria may be different from the voltage limits determined in approved TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-1, R3			
			System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.

VSL Justifications – TPL-007-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R5. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-1, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the BES meets performance criteria. Proposed TPL-007-1 Requirement R3 requires responsible entities to complete a GMD Vulnerability Assessment to ensure the system meets performance criteria during a benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in

Proposed VSLs – TPL-007-1, R4			
months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

VSL Justifications – TPL-007-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R4	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A VRF of Medium is also consistent with approved IRO-010-1a Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-1 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R5			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R5			
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved MOD-032-1, Requirement R2 and IRO-010-1a, Requirement R3, which also have a graduated scale for VSLs.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R5	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-1 Requirement R6 requires responsible entities to conduct a thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely

Proposed VSLs – TPL-007-1, R6			
owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in	three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in	owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.

Proposed VSLs – TPL-007-1, R6			
	Requirement R6, Parts 6.1 through 6.3.	Requirement R6, Parts 6.1 through 6.3.	

VSL Justifications – TPL-007-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved FAC-008-3, Requirement R6. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications – TPL-007-1, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-1 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While approved TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-1 has split the requirements for performing a GMD Vulnerability Assessment and development of the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Exhibit H

Analysis of Commission Directives

Order No. 779 Citation	Directive/Guidance	Resolution
P 2	Within 18 months of the effective date of this final rule, NERC must submit for approval one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.	The proposed standard requires applicable Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners to conduct periodic assessments of the impacts of a 100-year benchmark GMD event on their systems.
P 2	The Second Stage GMD Reliability Standard must identify what severity GMD events (i.e. benchmark GMD events) that responsible entities will have to assess for potential impacts on the Bulk-Power System.	The benchmark GMD event is described in the drafting team's white paper available on the project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx The benchmark provides a defined event for assessing system performance as required by the proposed standard. It defines the geoelectric field values used to compute geomagnetically-induced current flows for a GMD Vulnerability Assessment.
P 28	We expect that NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards.	The directive was met in the development of the proposed standard. The SDT chose a planning standard approach to meet the directives for the second stage GMD reliability standards, which allows responsible entities latitude to select mitigation from a variety of considerations which may include cost. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations. Comments on mitigation costs were solicited from stakeholders during formal comments and considered by the SDT.

Order No. 779 Citation	Directive/Guidance	Resolution
P 51	The Commission accepts the proposal in NERC's May 21, 2012 post-Technical Conference comments and directs NERC to "identify facilities most at-risk from severe geomagnetic disturbance" and "conduct wide-area geomagnetic disturbance vulnerability assessment" as well as give special attention to those Bulk-Power System facilities that provide service to critical and priority loads. As noted...owners and operators of the Bulk-Power System will perform the assessments.	When fully implemented, the proposed standard will enable wide-area assessment of GMD impact by owners and operators. Through the standard development process, industry has provided projections on the time required for obtaining validated tools, models, and data necessary for conducting GMD Vulnerability Assessments. The five-year phased Implementation Plan has been tailored accordingly and reflects a realistic timeline for expecting owners and operators to perform GMD Vulnerability Assessments. Corrective Action Plans required by the proposed standard provide the means to address risk to all facilities from a benchmark GMD event, not only those determined to be most at-risk in wide-area assessments. The proposed standard enhances NERC's ability to further assess the reliability risks that geomagnetic disturbances pose to the Bulk-Power System through the reliability assessment functions described in Section 800 of the NERC Rules of Procedure. During the five-year implementation period, NERC will closely support industry preparations, monitor implementation, and assess progress and initial results. Once the proposed standard is fully implemented, NERC and the Regional Entities will be better able to further assess the potential impacts of GMD events on the Bulk-Power System as a whole and update the 2012 Interim Report.
P 67	Each responsible entity under the Second Stage GMD Reliability Standards would then be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR [P 28 - 32] and adopted in this Final Rule.	The proposed standard requires applicable entities to perform assessments that will identify the impacts from benchmark GMD events on the interconnected transmission system. • Evaluation criteria are uniformly established in Requirement R4, Table 1, and Attachment 1.

Order No. 779 Citation	Directive/Guidance	Resolution
	• First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments... • Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers[1], including the effects of GICs originating from and passing to other regions. • Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues • Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed... • Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.	o Requirement R4 specifies system conditions. o Table 1 establishes uniform performance criteria. o Attachment 1 describes the procedure for calculating the benchmark GMD event for use in the GMD Vulnerability Assessment. • Requirements R4 and R6 address assessments of the effects of GIC on applicable transformers. o Requirement R4 specifies that responsible planning entities must conduct GMD Vulnerability Assessments that include steady state analysis to ensure transformer reactive losses from a benchmark GMD event do not produce voltage collapse, Cascading, and uncontrolled islanding. o Requirement R6 specifies that Transmission Owners and Generator Owners must conduct thermal impact assessments of applicable power transformers. • Requirements R4 and Table 1 address assessments of the effects of GIC on other Bulk-Power System equipment. Table 1 specifies that Reactive Power compensation devices and other Transmission Facilities are removed in the GMD study as a result of Protection System operation or Misoperation due to harmonics. Thus the GMD Vulnerability Assessment includes the system effects caused by GIC impacts on other BPS equipment. • The proposed standard accounts for wide-area impacts by requiring information exchange and involving appropriate applicable entities. Requirement R4 and Requirement R7 specify that GMD Vulnerability Assessments and Corrective Action Plans must be provided to Reliability Coordinators, adjacent planning entities, and functional entities

[1] The NOPR described damage to Bulk-Power System components as a primary effect of GICs and production of harmonics that are not present during normal Bulk-Power System operation and increased transformer absorption of reactive power as secondary effects of GICs. NOPR, 141 FERC ¶ 61,045 at P 13.

Order No. 779 Citation	Directive/Guidance	Resolution
		specifically referenced in the plans. Reliability Coordinators work together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function. Planning Coordinators integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. • The proposed standard requires GMD Vulnerability Assessments to be periodically updated, not to exceed every 60 calendar months.
P 67	The NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate assessments across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness.	Planning Coordinators are included as applicable entities in the proposed standard to integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. Requirement R1 in the proposed standard requires the Planning Coordinator to "identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s)". Requirement R4 specifies that GMD Vulnerability Assessments are provided to adjacent Planning Coordinators. Requirement R7 specifies that Corrective Action Plans are provided to adjacent Planning Coordinators. These requirements provide the necessary information exchange for planning activities. In addition, the proposed standard designates Reliability Coordinators as a recipient of GMD Vulnerability Assessments and Corrective Action Plans. Reliability Coordinators work

Order No. 779 Citation	Directive/Guidance	Resolution
		together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function.
P 68	NERC should consider developing Reliability Standards that can incorporate improvements in the scientific understanding of GMDs. When developing the Second Stage GMD Reliability Standards implementation schedule, NERC should consider the availability of validated tools, models, and data necessary to comply with the Requirements.	The requirements in the proposed standard are performance-based which allow applicable entities to use state of the art tools and methods to accomplish the specified reliability objectives. The standard does not contain prescriptive requirements for entities to use specific tools, models, or procedures which would limit the applicability of improvements in scientific understanding. Furthermore the use of modern magnetometer data and statistical methods in determining the benchmark GMD event supports reevaluation as additional magnetometer data is collected during future solar cycles. The 5-year phased implementation period was developed with consideration for the availability of validated tools, models, and data required by applicable entities.
P 79	If the assessments identify potential impacts from benchmark GMD events, owners and operators must develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event. • Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training alone, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the benchmark GMD events	The directive is met by requiring an entity to develop a Corrective Action Plan in the event its system fails to meet specified performance criteria. Requirement 7, Part 7.1 lists acceptable actions which are not limited to considering Operating Procedures or enhanced training.

Order No. 779 Citation	Directive/Guidance	Resolution
	based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.	
P 82	As with the First Stage GMD Reliability Standards, the responsible entities should perform vulnerability assessments of their own systems and develop the plans for mitigating any identified vulnerabilities. We take no position in this Final Rule on which functional entities should be responsible for compliance under the Second Stage GMD Reliability Standards. However, the NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate mitigation plans across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness. We clarify that if a responsible entity performs the required GMD vulnerability assessments and finds no potential GMD impacts, no plan is required under the Second Stage GMD Reliability Standards.	The proposed standard requires applicable entities to conduct assessments on their systems and develop plans to mitigate identified vulnerabilities. In Requirement R1, Planning Coordinators and Transmission Planners identify responsibilities for maintaining models and performing studies needed for GMD Vulnerability Assessments specified in Requirement R4. In Requirement R6, Transmission Owners and Generator Owners are required to conduct thermal impact assessments of applicable BES power transformers and, if necessary, specify mitigating actions. Requirement R7 specifies that the applicable planning entity must develop a Corrective Action Plan in the event that it concludes through the GMD Vulnerability Assessment that the system does not meet performance requirements. An entity that performs a GMD Vulnerability Assessment and does not identify a deficiency in system performance is not required to develop a Corrective Action Plan.
P 84	The Second Stage GMD Reliability Standards should not impose “strict liability” on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity.	The proposed standard is a planning standard where the benchmark GMD event is the planning basis. The standard does not impose strict liability on failure to ensure reliable operation during a GMD event of unforeseen severity.
P 85	Given that some responsible entities have or may choose automatic blocking measures, the NERC standards development process should consider how to verify that selected blocking measures are effective and consistent with the reliable operation of the Bulk-Power System.	The GMD Vulnerability Assessment process considers all mitigation measures in modeling, assessment, and mitigation requirements. Requirement R2 specifies that responsible entities shall maintain system models for performing GMD Vulnerability

Order No. 779 Citation	Directive/Guidance	Resolution
		Assessments, which will include automatic blocking measures that are part of the system as described in the technical guidance. The responsible entity must perform studies based on these models as required in Requirement R4 to verify effectiveness and the reliable operation of the system. When a responsible entity identifies a need for mitigation actions such as blocking measures, Requirement R6 and R7 specify that information must be shared with planning entities to ensure that the mitigation actions are consistent with reliable operation.
P 86	While responsible entities will decide how to mitigate GMD vulnerabilities on their systems, the NERC standards development process should consider how the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic measures including, for example, some combination of blocking, improved "withstand" capability, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.	The directive is met in Requirement R7. Responsible entities that conclude through the GMD Vulnerability Assessment that their System does not meet performance requirements are required to develop a Corrective Action Plan. The plan must list deficiencies and the associated actions needed to achieve required performance. Requirement R7 provides examples of such actions: installation or modification of equipment, use of Operating Procedures, and other actions specified in the requirement.
P 91	NERC must propose an implementation plan.	The implementation plan was developed through the standards development process.
P 91	We do not direct or suggest a specific implementation plan. As stated in the NOPR, in a proposed implementation plan, we expect that NERC will consider a multi-phased approach that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable operation of the Bulk-Power System are protected first. We also expect, as discussed above, that the implementation plan will take into account the availability of validated tools, models, and data that are necessary for	Compliance with the proposed standard is to be implemented over a 5-year period as described in the Implementation Plan. Phased implementation provides • Necessary time for entities to obtain tools, models, and data required for GMD vulnerability assessments • Proper sequencing of system and equipment assessments performed by various applicable functional entities to build an overall assessment of GMD vulnerability.

Order No. 779 Citation	Directive/Guidance	Resolution
	responsible entities to perform the required GMD vulnerability assessments.	• Adequate time for development of viable Corrective Action Plans that detail actions and timelines necessary to achieve required performance. Development of Corrective Action Plans may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc. to meet the TPL-007-1 requirements.

Exhibit I

Summary of Development History and Complete Record of Development

Exhibit I—Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard TPL-007-1.

The development record for proposed Reliability Standard TPL-007-1 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit J**.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was posted for a formal comment period from June 27, 2013 to August 12, 2013. The Standards Committee approved the SAR on June 21, 2013.

B. First Posting – Informal Comment Period

Proposed Reliability Standard TPL-007-1 was posted for a 30-day informal public comment period from April 22, 2014 through May 21, 2014. The drafting team considered stakeholder comments in revising proposed Reliability Standard TPL-007-1 and made a number of changes based on those comments.

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

C. Second Posting – Formal Comment Period

Proposed Reliability Standard TPL-007-1 was posted for a 45-day formal public comment period from June 13, 2014 through July 30, 2014, with an initial ballot held from July 21, 2014 to July 30, 2014. The initial ballot received an 82.67% quorum, and an approval of 55.7%. The non-binding poll achieved an 82.56% quorum and 58.65% of supportive opinions. There were 74 sets of responses, including comments from approximately 180 individuals from approximately 130 companies representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard TPL-007-1 and made the following modifications and observations based on those comments:

- Changed the overall implementation schedule from 4 years to 5 years to address stakeholder concerns with coordination, model development, and resource limitations. The revised implementation plan provided six-months from the effective date of the standard for Planning Coordinators and Transmission Planners to identify responsibilities (R1) and extended other requirements in a similar manner. Additionally, the initial performance of transformer thermal impact assessments was extended to 48 calendar months from the effective date.
- Modified Requirement R3 (previously R4) to allow responsible entities more flexibility in determining the acceptable voltage performance criteria.
- Added language to Requirement R6 to clearly indicate that the requirement would apply to Bulk Electric System power transformers meeting the applicability section 4.2 of the proposed standard. The timeline for completing thermal assessments was increased from 12 calendar months to 24 calendar months from receipt of required information from the planning entity. Also, the VRF was changed from High to Medium.
- Revised Table 1 – Steady State Planning to remove guidance that may have restricted manual or automatic Load shedding to meet performance requirements. This change was intended to further the project’s intent of developing standards to prevent voltage collapse, Cascading, and uncontrolled islanding during a 100-year benchmark event. Additionally, the drafting team removed duplicative notes from Table 1.
- Revised Attachment 1 – Calculating Geoelectric Fields for the Benchmark GMD Event to revise guidance for assuming an earth conductivity scaling factor when a model is not known. Attachment 1 was revised to allow planners to select a conservative scaling factor from an adjacent physiographic region rather than use a default value. Also, an earth conductivity scaling factor was added to Table 3 for Florida, based on research by the U.S. Geological Survey.

- Reordered Requirements in response to stakeholder recommendations for a more logical sequencing. Several clarifications were made to the requirements, measures, and supporting material.
- Several stakeholders commented on the 15 A screening criterion proposed by the drafting team for transformer thermal impact assessment. The drafting team considered a stakeholder recommendation to establish a separate, higher threshold for three-phase power transformers, but concluded that there was insufficient thermal measurement data of three-phase three-limb transformers to develop a technical justification at that time.

D. Third Posting – Formal Comment Period and Additional Ballot

Proposed Reliability Standard TPL-007-1 was posted for a 45-day formal public comment period from August 27, 2014 through October 10, 2014, with an additional ballot held from October 1, 2014 to October 10, 2014. The additional ballot received an 82.93% quorum, and an approval of 57.95%. The additional non-binding poll achieved an 81.69% quorum and 59.63% of supportive opinions. There were 58 sets of responses, including comments from approximately 175 individuals from companies and organizations representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard TPL-007-1 and the supporting material and made the following modifications based on those comments:

- Revised the effective GIC value for applicable Bulk Electric System power transformers requiring thermal impact assessments from 15 A per phase to 75 A per phase, with justification provided in the revised White Paper on Screening Criterion for Transformer Thermal Impact Assessment.
- Revised the Transformer Thermal Impact Assessment White Paper to include a simplified method for performing a transformer thermal assessment.
- Made editorial changes for clarity to Requirements R1 through R4.
- Revised Requirement R5 to be consistent with the 75 A per phase GIC threshold for transformer thermal assessments. The drafting team also modified Requirement R5 to no longer require the planning entity to provide the GIC time series to all Transmission Owners and Generator Owners, but to do so upon request.
- Revised Requirement R6 to include the 75 A per phase GIC threshold for transformer thermal assessments.
- Made editorial changes for clarity to Requirement R7.
- Revised evidence retention periods.

- Changed the VRF for Requirement R2 from Medium to High to be consistent with the corresponding requirement in TPL-001-4.
- Revised the Rationale and Application Guidelines sections to provide additional explanations.

E. Fourth Posting – Formal Comment Period and Additional Ballot

Proposed Reliability Standard TPL-007-1 was posted for a 25-day formal public comment period from October 28, 2014 through November 21, 2014,[2] with an additional ballot held from November 12, 2014 to November 21, 2014. The additional ballot received a 79.73% quorum, and an approval of 77.29%. The additional non-binding poll achieved a 78.78% quorum and 69.67% of supportive opinions. There were 50 sets of responses, including comments from approximately 100 individuals from approximately 70 companies representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard TPL-007-1 and the supporting materials and made the following clarifying and non-substantive changes modifications based on those comments:

- Requirement R1: corrected VRF terminology from "Low" to "Lower."
- Revised Requirement R6 Part 6.4 to clarify that the thermal assessments must be performed within 24 calendar months of receipt of GIC flow information specified in “Requirement R5, Part 5.1” and made a corresponding change to the VSL for Requirement R6.
- Revised the Rationale and Application Guidelines sections for clarity.
- Made punctuation and grammatical changes throughout the standard.
- In the White Paper on Screening Criterion for Transformer Thermal Impact Assessment:
    - Added clarification on page 3 to indicate that the stated temperature refers to full load bulk oil temperature.
    - Corrected table numbering and the example on page 8.

[2] On its regularly-scheduled October 22, 2014 teleconference, the Standards Committee authorized a waiver of the Standard Process, shortening the next formal comment period (and any subsequent additional formal comment periods) for draft standard TPL-007-1 from 45 days to 25 days. The Notice of Request to Waive the Standard Process was submitted to the Standards Committee on October 15, 2014. The Standards Committee’s teleconference was noticed through an announcement and posted on the NERC website.

F. Final Ballot

Proposed Reliability Standard TPL-007-1 was posted for a 10-day final ballot period on December 5, 2014 through December 16, 2014.[3] The proposed Reliability Standard received a quorum of 84.27% and an approval rating of 78.05%.

G. Board of Trustees Approval

Proposed Reliability Standard TPL-007-1 was approved by the NERC Board of Trustees on December 17, 2014.

[3] The final ballot close date was extended one day to December 16, 2014 due to a NERC.com maintenance outage that occurred Saturday, December 13, 2014.

Project 2013-03 Geomagnetic Disturbance Mitigation

Related Files

Status:
A final ballot for **TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events** concluded at **8 p.m. Eastern on Tuesday, December 16, 2014**. Voting results can be accessed via the link below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background:
FERC issued order 779 in May 2013 directing NERC to develop reliability standards to address the potential impact of geomagnetic disturbances (GMDs) on the reliability operation of the Bulk-Power System. Since 2010, industry has taken steps to address the GMD risk scenario identified in the 2010 High Impact Low Frequency (HILF) Event joint report through the Geomagnetic Disturbance (GMD) Task Force, which is comprised of industry representatives, government partners, and GMD experts. The GMD Task Force published an interim report on the effects of GMD on the Bulk-Power System in April 2012 and provided recommendations to manage risk. The task force's current project is focused on providing tools for system operators and planners to assess GMD effects on the system and implement mitigating strategies when needed.

Purpose/Industry Need:
Project 2013-03 will develop reliability standards to mitigate the risk of instability, uncontrolled separation, and Cascading as a result of geomagnetic disturbances (GMDs) through application of Operating Procedures and strategies that address potential impacts identified in a registered entity's assessment as directed in FERC Order 779.

While the impacts of space weather are complex and depend on numerous factors, space weather has demonstrated the potential to effect the reliable operation of the Bulk-Power System. During a GMD event, geomagnetically-induced current (GIC) flow in transformers may cause half-cycle saturation, which can increase absorption of Reactive Power, generate harmonic currents, and cause transformer hot spot heating. Increased transformer Reactive Power absorption and harmonic currents associated with GMD events can also cause protection system Misoperation and loss of Reactive Power sources, the combination of which can lead to voltage collapse.

The project will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading caused by GMD in two stages as directed in order 779:

1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures that can mitigate the effects of GMD events.
2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in order 779. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts on the Bulk-Power System. If the assessments identify potential impacts from benchmark GMD events, the Reliability Standards will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of a benchmark GMD event. The development of this plan cannot be limited to considering operational procedures or enhanced training alone, but will, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for mitigating the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.

As directed in order 779, stage 1 standards must be filed by January 2014, and stage 2 standards must be filed by January 2015.

<table>
<tr><th>Draft</th><th>Action</th><th>Dates</th><th>Results</th><th>Consideration of Comments</th></tr>
<tr><td rowspan="2">Final Draft

TPL-007-1
Clean (68) | Redline to Last Posted (69)

Implementation Plan
Clean (70) | Redline to Last Posted (71)

Supporting Materials</td><td>Final Ballot

Info>> (81)

Vote>></td><td>12/05/14 – 12/16/14

(closed)</td><td rowspan="2">Summary>> (82)

Ballot Results>> (83)</td><td rowspan="2"></td></tr>
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Clean (72) | Redline to Last Posted (73)

Transformer Thermal Impact Assessment White Paper
Clean (74) | Redline to Last Posted (75)

Thermal Screening Criterion White Paper
Clean (76) | Redline to Last Posted (77)

VRF/VSL Justification
Clean (78) |Redline to Last Posted (79)

Consideration of Directives (80)</td>
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Stage 2 Standard
TPL-007-1
Clean (49) | Redline to Last Posted (50)

Implementation Plan
Clean (51) | Redline to Last Posted (52)

Supporting Materials
Unofficial Comment Form (Word) (53)

Benchmark GMD Event White Paper
Clean (54) | Redline to Last Posted (55)

Transformer Thermal Impact Assessment White Paper
Clean (56) | Redline to Last Posted (57)

Thermal Screening Criterion White Paper (58)
(Complete Revision)

VRF/VSL Justification (59)

Consideration of Directives (60)

Draft RSAW
Clean | Redline</td>
<td>Additional Ballot and Non-Binding Poll

Info>> (61)

Vote>></td>
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(closed)</td>
<td>Summary>> (63)

Ballot Results>> (64)

Non-Binding Poll Results>> (65)</td>
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Submit Comments>></td>
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(closed)</td>
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RSAWfeedback@nerc.net</td>
<td>11/05/14 - 11/21/14

(closed)</td>
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Notice of Request to Waive the Standard Process (48)				
Draft 3 **Stage 2 Standard** **TPL-007-1** Clean (29) | Redline to Last Posted (30) **Implementation Plan** Clean (31) | Redline to Last Posted (32) **Supporting Materials** Unofficial Comment Form (Word) (33) **Benchmark GMD Event White Paper** Clean (34) | Redline to Last Posted (35) **Transformer Thermal Impact Assessment White Paper** Clean (36) | Redline to Last Posted (37) **Thermal Screening Criterion White Paper (38)** **VRF/VSL Justification (39)** **Draft RSAW** Clean | Redline	Additional Ballot and Non-Binding Poll Updated Info>> (40) Info>> (41) Vote>>	10/01/14 - 10/10/14 (closed)	Summary>> (43) Ballot Results>> (44) Non-Binding Poll Results>> (45)	
	Comment Period Info>> (42) Submit Comments>>	08/27/14 - 10/10/14 (closed)	Comments Received>> (46)	Consideration of Comments>> (47)
	Please send RSAW feedback to: RSAWfeedback@nerc.net	09/11/14 - 10/10/14		
Draft 2 **Stage 2 Standard** **TPL-007-1** Clean (9) | Redline to Last Posted (10)	Ballot and Non-Binding Poll Updated Info>> (20) Info>> (21) Vote>>	07/21/14 – 07/30/14 (closed)	Summary>> (23) Ballot Results>> (24) Non-Binding Poll Results>> (25)	
	Comment Period Info>> (22) Submit Comments>>	06/13/14 - 07/30/14 (closed)	Comments Received>> (26) Additional Comments Received>> (27)	Consideration of Comments>> (28)

Implementation Plan Clean **(11)** | Redline to Last Posted **(12)** **Supporting Materials** Unofficial Comment Form (Word) **(13)** **Benchmark GMD Event White Paper** Clean **(14)** | Redline to Last Posted **(15)** (Updated 6/19/2014 to correct figure I-2) **Transformer Thermal Impact Assessment White Paper** Clean **(16)** | Redline to Last Posted **(17)** Thermal Screening Criterion white paper **(18)** Common Questions and Responses **(19)** Draft Reliability Standard Audit Worksheet (RSAW)	Join Ballot Pool>>	6/13/14 – 07/14/14 (closed)		
Draft 1 **Stage 2 Standard** TPL-007-1 **(2)** Implementation Plan **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)** Benchmark GMD Event White Paper **(5)** Transformer Thermal Impact Assessment White Paper **(6)**	Comment Period Info>> **(7)** Submit Comments>>	04/22/14 - 05/21/14 (closed)	Comments Received>> **(8)**	
Draft 3 **Stage 1 Standard** EOP-010-1 Clean | Redline to last posting Implementation Plan Clean | Redline to last posting **Supporting Materials:**	Final Ballot Info>> Vote>>	10/25/13 - 11/04/13 (closed)	Summary>> Ballot Results>>	

Standard Authorization Request White Paper Supporting Network Applicability of EOP-010-1 Clean | Redline to last posting White Paper Supporting Functioning Entity Applicability of EOP-010-1 Clean | Redline to last posting GMD Task Force Operating Procedures Waiver Authorized by SC but not Exercised Violation Risk Factor and Violation Severity Level Justifications Stage 1 Directives Map				
Draft 2 **Stage 1 Standard** **EOP-010-1** Clean | Redline to last posting **Implementation Plan** Clean | Redline to last posting **Supporting Materials:** Unofficial Comment Form (Word) Standard Authorization Request White Paper Supporting Network Applicability of EOP-010-1 White Paper Supporting Functional Entity Applicability of EOP-010-1 GMD Task Force Operating Procedures	Comment Period Info>> Submit Comments>>	09/04/13 - 10/21/13 (closed)	Summary>> Ballot Results>> Non-binding Poll Results>> Comments Received>>	Consideration of Comments>>
	Additional Ballot and Non-Binding Poll Updated Info>> Info>> Vote>>	10/09/13 - 10/21/13 Extended an additional day to achieve quorum. (closed)		
Draft Stage 1 Standard EOP-010-1 Implementation Plan	Comment Period Info>> Submit Comments>>	06/27/13 - 08/13/13 (closed)	Summary>>	Consideration of Comments>>
	Ballot and Non-binding Poll Info>> Vote>>	08/02/13 - 08/13/13 (closed)		
	Join Ballot Pool>>	06/27/13 - 07/26/13 (closed)		

Standard Authorization Request **(1)** **Supporting Materials:** Unoffical Comment Form (Word) GMD Task Force Operating Procedures			Ballot Results>> Non-binding Poll Results>> Comments Received>>	

Standards Authorization Request Form

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	EOP-010-1 Geomagnetic Disturbance Operations TPL-007-1 Transmission System Planned Performance During Geomagnetic Disturbances		
Date Submitted:			
SAR Requester Information			
Name:	Kenneth Donohoo, Oncor		
Organization:	Chair, Geomagnetic Disturbance Task Force		
Telephone:	NA	E-mail:	NA
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
To mitigate the risk of instability, uncontrolled separation, and Cascading in the Bulk-Power System as a result of geomagnetic disturbances (GMDs) through application of Operating Procedures and strategies that address potential impacts identified in a registered entity's assessment as directed in FERC Order 779.
Industry Need (What is the industry problem this request is trying to solve?):
While the impacts of space weather are complex and depend on numerous factors, space weather has demonstrated the potential to disrupt the operation of the Bulk-Power System. A technical discussion of the effects of geomagnetic disturbances on the Bulk-Power System and recommended actions for NERC and the industry is provided in the NERC 2012 GMD Report prepared by the GMD Task Force. During a GMD event, geomagnetically-induced current (GIC) flow in transformers may cause half-cycle

SAR Information
saturation, which can increase absorption of Reactive Power, generate harmonic currents, and cause transformer hot spot heating. Harmonic currents may cause protection system Misoperation leading to the loss of Reactive Power sources. The combination of these effects from GIC can lead to voltage collapse.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed project will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in Order 779: 1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures with predetermined and actionable steps to take prior to and during GMD events which take into account entity-specific factors that can impact the severity of GMD events in the local area. The Stage 1 standard(s) may also include associated training requirements for System Operators or development of training requirements may be deferred to Stage 2. 2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. The Stage 2 standard(s) must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts. If the assessments identify potential impacts from benchmark GMD events, the Standard(s) will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The standards development project will respond to the directives in FERC Order 779 in the timeframe required by the Order and draw upon the technical products of the GMD Task Force Phase 2 Project and other relevant information. The GMD Task Force Phase 2 Project addresses the recommendations in the 2012 GMD Report and is focused on improving the capabilities of industry to assess GMD risk and develop appropriate mitigation strategies.

SAR Information
Operating Procedures are the first stage in the Standards project to manage risks associated with GMD events with accompanying training requirements to be addressed in Stage 1 or 2 as determined by the Standards Drafting Team. Specifically, the project will require owners and operators of the Bulk-Power System to develop and implement Operating Procedures and accompanying operator training which may include: • Procedures for acquiring and disseminating forecasting information and warning messages from the space weather forecasting community to the System Operators; • Predetermined and actionable steps for System Operators to take prior to and during a GMD event that are tailored to the registered entity's assessment of entity-specific factors such as geography, geology, and system topology; • Procedures to notify and coordinate with interconnected registered entities for effective action; • Restoration procedures for applicable elements that may be impacted; • Minimum training requirements for System Operators; and • Criteria for discontinuing the use of Operating Procedures at the conclusion of a GMD event. The second stage of the project will require applicable registered entities to conduct initial and periodic assessments of the risk and potential impact of benchmark GMD events to the Bulk-Power System and develop strategies to mitigate the risk of instability, uncontrolled separation, and Cascading. • The definition of benchmark GMD events will be based on reviewed technical analysis. • Periodic update of the assessments will be required to account for new Facilities and modifications to existing Facilities. It is expected that assessments will also consider new information and the use of new or updated tools, including new research on GMDs and the on-going work of the NERC GMD Task Force. • The Standard(s) will require Planning Coordinators and Reliability Coordinators to review plans addressing the potential impact of benchmark GMD events in order to provide a wide-area perspective. The Standard Requirements for plans will be supported by reviewed technical analysis, with consideration of the directives in FERC Order 779. When both stages have been completed as required by FERC Order 779, all directives in the Order will have been addressed.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.

Reliability Functions		
☒	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance	Yes

Reliability and Market Interface Principles	
with that standard.	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PER-005-1, R3	Training on GMD events and mitigation procedures will be added to this requirement as a specific element in required operator training unless included in a separate GMD standard.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	
The intent of the project is to develop continent-wide requirements that allow responsible entities to tailor operational procedures or strategies based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology. However, the need for regional variances will be researched throughout the proposed project and may be supported by analysis required to develop stage 2 Standard(s).	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.

Description of Current Draft

This draft is the first posting of the proposed standard. It is posted for a 30-day informal comment.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June 2014
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

The definition shall become effective on the first day of the first calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance shall be implemented over a 4-year period as described in the Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a Planning Coordinator area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.2 Transmission Planner with a Transmission Planning area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.3 Transmission Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.4 Generation Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator and Transmission Planner shall maintain ac System models and geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. The System models shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Existing Facilities

1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.3. New planned Facilities and changes to existing Facilities

1.4. Real and reactive Load forecasts

1.5. Known commitments for Firm Transmission Service and Interchange

1.6. Resources (supply or demand side) required for Load

M1. Each Planning Coordinator and Transmission Planner shall have evidence in either electronic or hard copy format that it is maintaining ac System models and geomagnetically-induced current (GIC) System models within its respective area, using data consistent with MOD standards including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

Rationale for Requirement R1:

A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The ac System model is used in conducting steady-state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

R2. Each Planning Coordinator and Transmission Planner shall complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Studies shall include the following conditions:

2.1.1. System peak Load for one year within the Near-term Transmission Planning Horizon.

2.1.2. System Off-Peak Load for one year within the Near-term Transmission Planning Horizon.

2.2 Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

M2. Each Planning Coordinator and Transmission Planner shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R2.

Rationale for Requirement R2:

GMD Vulnerability Assessment includes steady-state power flow analysis and supporting studies that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

R3. Each Planning Coordinator and Transmission Planner that determines through the GMD Vulnerability Assessment conducted in Requirement R2 that its System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

3.2. Be reviewed in subsequent GMD Vulnerability Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M3. Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R3.

R4. Each Planning Coordinator and Transmission Planner shall have criteria for acceptable System steady state voltage limits for its System during the GMD conditions described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage limits for its System in accordance with Requirement R4.

Rationale for Requirement R4:

System steady state voltage limits for GMD Vulnerability Assessment may by different from the limits used in the TPL-001 Planning Assessment. The planner must adhere to established limits that ensure the planned System achieves the performance requirements in Table 1.

R5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD Vulnerability Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the GMD Vulnerability Assessment in accordance with Requirement R5.

R6. Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1 If a recipient of the GMD Vulnerability Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M6. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of completion, and to any functional entity who has indicated a reliability related need within 30 days of a written request. Each Planning Coordinator and Transmission Planner shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R5.

Rationale for Requirement R6:
Distribution of GMD Vulnerability Assessment results and Corrective Action Plans provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies and planned mitigation measures may affect neighboring systems and should be taken into account by planners. Additionally, this GIC information is essential for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment.

R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. Be based on the benchmark GMD event described in Attachment 1 with peak geomagnetically-induced current (GIC) flows as modeled in the steady-state analysis conducted in Requirement R2

7.2. Document assumptions used in the analysis

7.3. Describe suggested actions and supporting analysis to mitigate the impact of geomagnetically-induced currents, if any.

M7. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher as specified in Requirement R7.

Rationale for Requirement R7:

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M8. Each Transmission Owner and Generator Owner shall have dated evidence such as postal receipts or email confirmation that it has provided a copy of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded wye windings connected at 200 kV or higher as specified in Requirement R7 to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located within the timeframe prescribed in Requirement R8.

Table 1 –Steady State Planning Events

Steady State:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of P8 planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

d. System steady state voltages shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner in accordance with Requirement R4.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P8 GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation during the GMD event[3]	Yes[4]	Yes[4]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for planning event P8 are described in Attachment 1 (Benchmark GMD Event).
3. Protection Systems may trip due to the effects of harmonics. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible.
4. The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude to be used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 1-1 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α can be computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)}$$

where L is the geomagnetic latitude in degrees

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 1-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
55	0.6
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 1-3. The peak geoelectric field, E_{peak}, to be used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table 1-2 that correlates to the ground conductivity map in Figure 1-1 or Figure 1-2. Along with the scaling factor α, β is applied to the reference geolectric field using the following equation to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment.

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

The earth models used to calculate Table 1-2 for the United States were obtained from publicly available magnetotelluric data that is published on the U. S. Geological Survey website[3]. The models used to calculate Table 1-2 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. NRCan also has developed some models for sub-regions which should be used when available. Because all models in Table 1-2 are approximations, a planner can substitute a technically justified earth model for its planning area when available.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

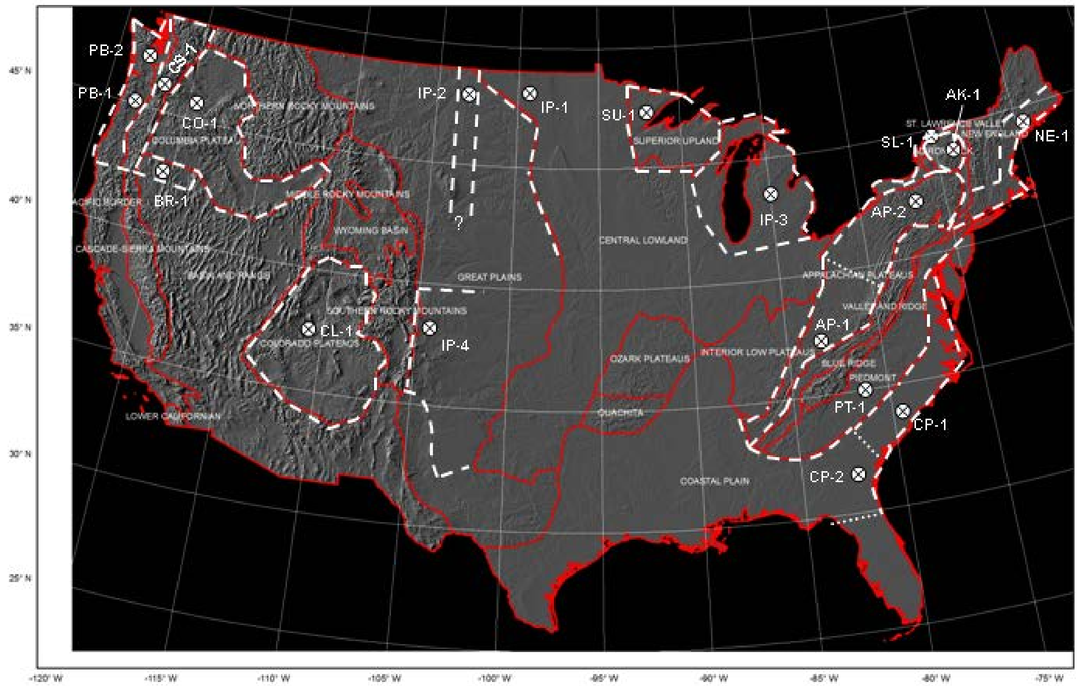

Figure 1-1: Physiographic Regions of the Continental United States[4]

Figure 1-2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 1-2 Geoelectric Field Scaling Factors

USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 1-3: Reference Earth Model (Quebec)

Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 when performing thermal analysis of power transformers.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 1-3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. 1-4 and 1-5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6]

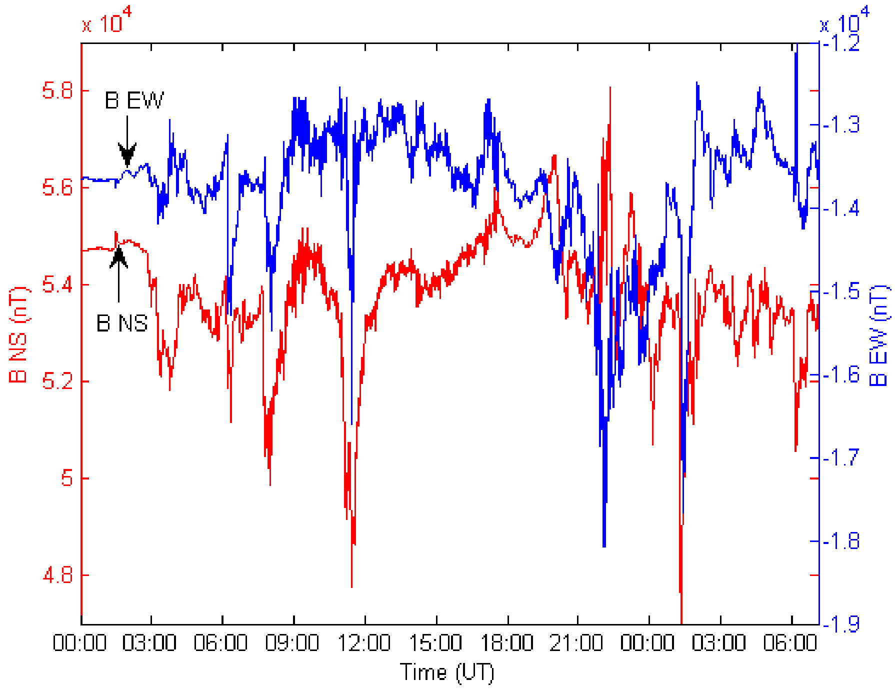

Figure 1-3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

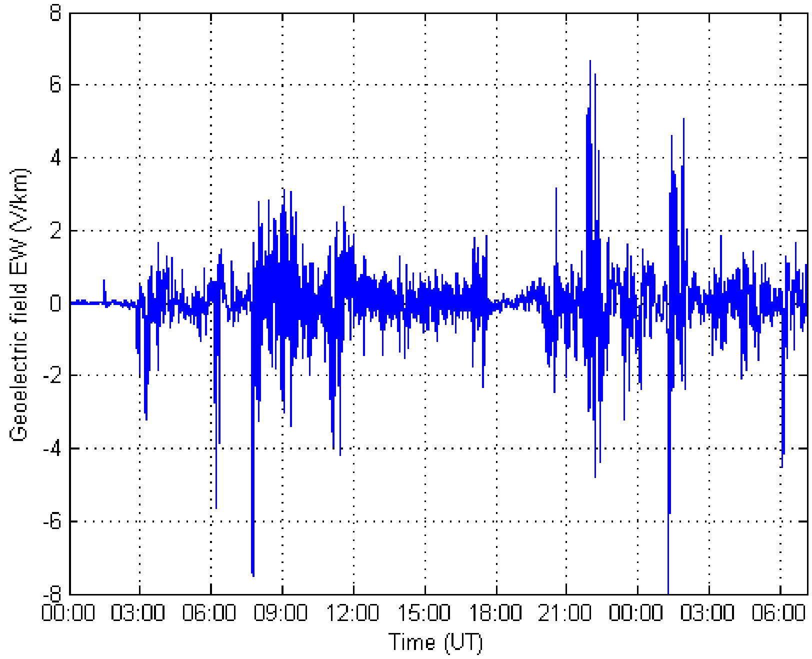


Figure 1-4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

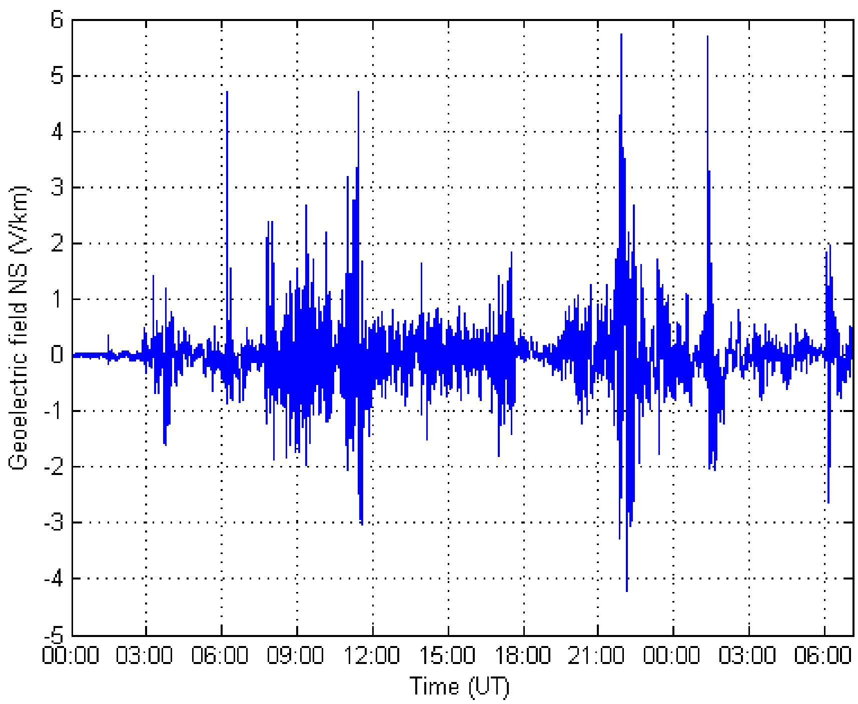


Figure 1-5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include one of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include two of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include three of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include four or more of the elements in Requirement R1, Parts 1.1 through 1.6; OR The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not represent projected System conditions as described in Requirement R1; OR The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not use data consistent with the MOD standards including items represented in the Corrective Action Plan.

R2	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to include one of the following Parts of Requirement R2: Part 2.1 or 2.2; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to include two of the following Parts of Requirement R2: Part 2.1 or 2.2; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R3	Long-term Planning	High	N/A	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R3 parts 3.1 and 3.2.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R3 parts 3.1 and 3.2; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R3.

R4	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits for its System during the GMD conditions as required.
R5	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R6	Long-term Planning	Medium	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 90 days but less than or equal to 120 days following completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 120 days but less than or equal to 130 days following its completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 130 days but less than or equal to 140 days following its completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 140 days following its completion; OR

			OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 30 days but less than or equal to 40 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 30 days but less than or equal to 40 days following the receipt as specified in Part 6.1.	OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 40 days but less than or equal to 50 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 40 days but less than or equal to 50 days following the receipt as specified in Part 6.1.	OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 50 days but less than or equal to 60 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 50 days but less than or equal to 60 days following the receipt as specified in Part 6.1.	The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4; OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 60 days following the request; OR The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional

						entities having a reliability related need who requested the information in writing; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 60 days following the receipt as specified in Part 6.1; OR The responsible entity did not provide a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan as specified in Part 6.1.
R7	Long-term Planning	High	The responsible entity failed to conduct an assessment of thermal impact for 5% or less of its solely owned and jointly owned power transformers with high-side, wye-grounded	The responsible entity failed to include one of the required elements as listed in Requirement R7 parts 7.1 through 7.3; OR The responsible entity failed to conduct an assessment of thermal	The responsible entity failed to include two or more of the required elements as listed in Requirement R7 parts 7.1 through 7.3; OR The responsible entity failed to conduct an	The responsible entity failed to conduct an assessment of thermal impact for more than15% of its solely owned and jointly owned power transformers with high-side, wye-grounded

			windings rated 200 kV or higher.	impact for more than 5% up to (and including) 10% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher.	assessment of thermal impact for more than 10% up to (and including) 15% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher.	windings rated 200 kV or higher.
R8	Long-term Planning	Medium	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 90 days but less than or equal to 120 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 120 days but less than or equal to 130 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 130 days but less than or equal to 140 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 140 days following its completion. OR The responsible entity did not provide a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R1

A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R2

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

Requirement R3

Technical considerations for GMD mitigation planning are available in Chapter 5 of the GMD Planning Guide. Additional information is available in the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Requirement R7

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances

Approvals Required

TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a Planning Coordinator area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

Transmission Planner with a Transmission Planning area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

Transmission Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

Generation Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 4-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined in the Steady-state analysis.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirements R1 and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2, Requirement R4, and Requirement R6 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2, Requirement R4, and Requirement R6, shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R7 and R8 shall become effective on the first day of the first calendar quarter that is 36 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R7 and R8 shall become effective on the first day of the first calendar quarter that is 36 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **May 21, 2014**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 standard(s) that require applicable entities to develop and implement Operating Procedures were filed in November, 2013.
- Stage 2 standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 standards must be filed by January 2015.

This posting is soliciting informal comments on the draft standard, TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances, being developed to address the stage 2 directives. TPL-007-1 includes requirements for Planning Coordinators, Transmission Planners, Transmission Owners, and Generation Owners with planning areas or transformers connected at 200 kV or higher.

Paragraph numbers in the following questions refer to Order No. 779.

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

Questions on Draft 1 of TPL-007-1

1. **Applicability**. The draft TPL-007-1 standard applies to Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater. The drafting team believes these are the correct functional entities to meet the directives in Order No. 779 to evaluate the effects of GICs on Bulk-Power System transformers and other equipment (P.67), consider wide-area effects and coordinate across regions (P.67), and develop plans to address potential impacts (P. 79). Justification for the 200 kV voltage threshold may be found in the whitepaper that was developed by the drafting team for the stage 1 standard, EOP-010-1 – Geomagnetic Disturbance Operations. Do you agree that these are the correct functional entities to perform the functions required in the draft standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No

   Comments:

2. **Technical basis**. Directives in Order No. 779 specify that the assessments required by the stage 2 standard should account for several parameters including the use of studies and simulations to evaluate the effects of GIC on the Bulk-Power System transformers (P. 59). The drafting team believes that the studies and analysis required by the standard meet the assessment parameters directed by FERC and are supported by the technical guides referenced in the standard. Do you agree that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment and are supported by the technical guidance? If you do not agree, or you recommend alternative language in these requirements or additional technical material, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No

   Comments:

3. **Benchmark GMD Event**. In Order No. 779, FERC directed that NERC specify the benchmark GMD event to be used by entities for assessing potential impact on the Bulk-Power System through the standards development process (P.54). Accordingly, the drafting team has posted the proposed Benchmark GMD Event Description whitepaper on the project page along with the standard for comment during this comment period. The drafting team believes the proposed benchmark GMD event is consistent with existing utility best practices, provides the consistent assessment criteria

required by the FERC order, and supports assessment of the parameters specified by the directives.

Do you agree that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779? If you do not agree, please provide specific technically justified alternatives or suggestions for the drafting team to consider.

☐ Yes
☐ No

Comments:

4. **Implementation**. Order No. 779 does not direct a specific Implementation Plan, but sets an expectation for a multi-phased approach and consideration for the availability of tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments. The drafting team is proposing a phased implementation of TPL-007-1 over a 4-year period. The Implementation Plan provides 1) time for entities to develop the required models; 2) proper sequencing of assessments; and 3) time for development of viable Corrective Action Plans, which may require entities to develop, perform, and validate studies, assessments, and procedures. Do you support the approach taken by the drafting team in the proposed Implementation Plan, and if you are an applicable entity in the proposed standard is the proposed time frame and sequencing realistic?

☐ Yes
☐ No

Comments:

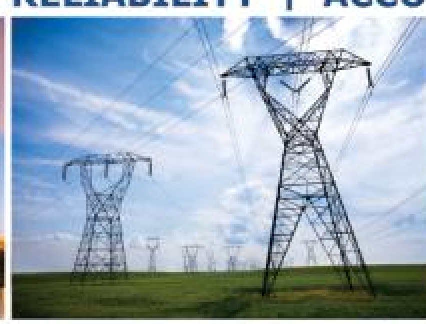
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
Draft: April 21, 2014

RELIABILITY | ACCOUNTABILITY



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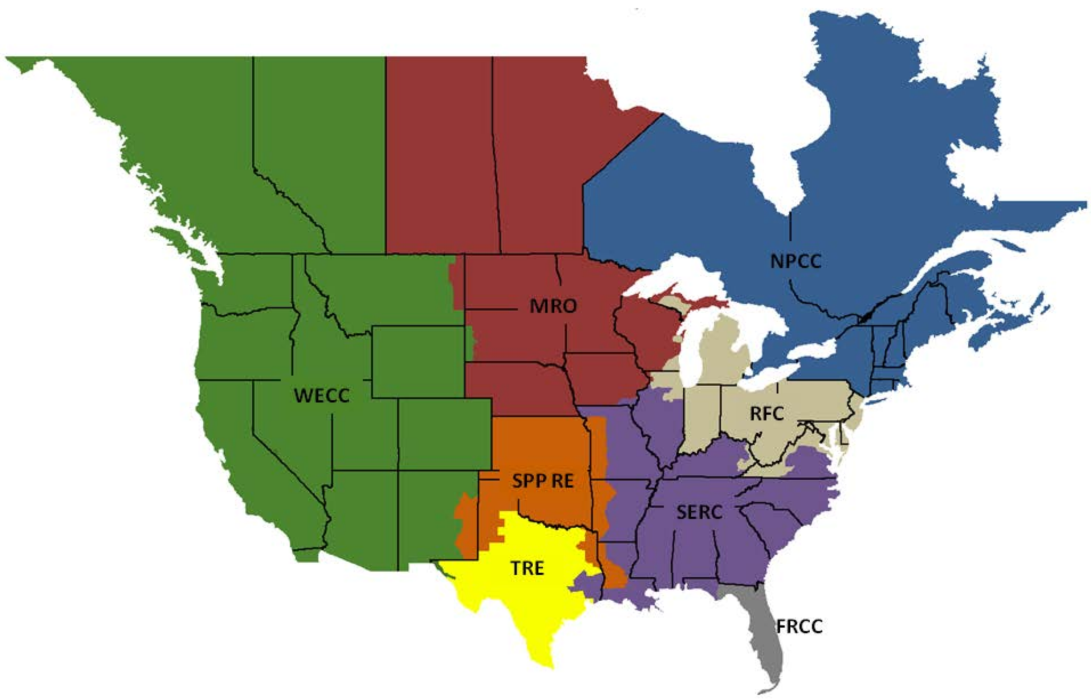
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide uniform evaluation criteria for assessing system performance during a low probability GMD event. It is to be used in conjunction with Reliability Standards that establish requirements for system modeling, vulnerability assessment, and mitigation planning. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. The Stage 1 Standard, EOP-010-1 is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increasing amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously and may take up to several seconds. From a practical point of view, assuming that the effects of GIC on transformer var absorption and harmonic generation are instantaneous is conservative.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability of occurrence of the event and the impact or consequences of the event. The benchmark event is composed of the following elements: (1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)

Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the “Halloween event” of October 29-31, 2003, and the

March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I).

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

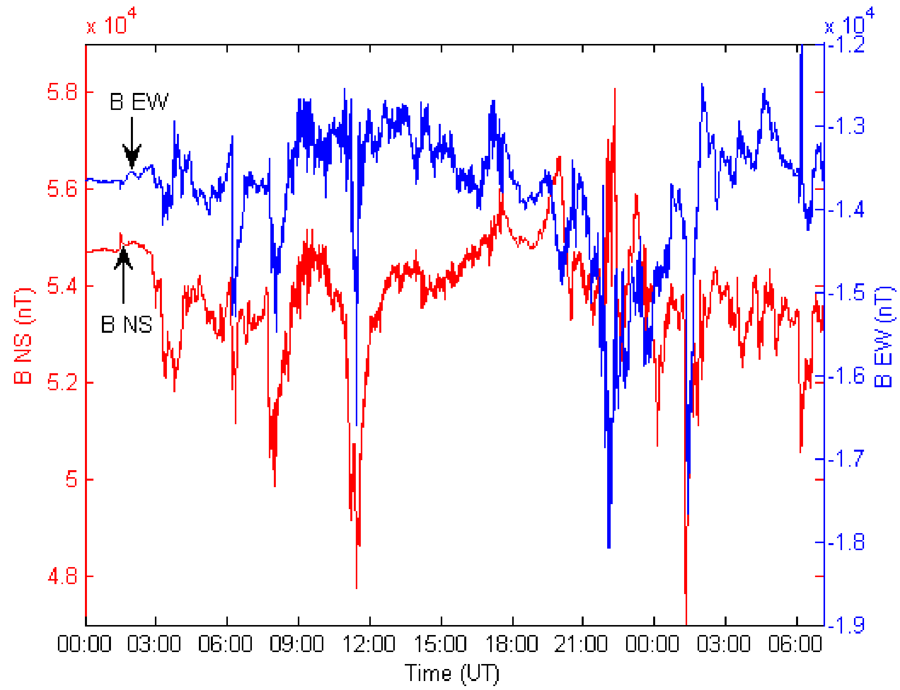


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)

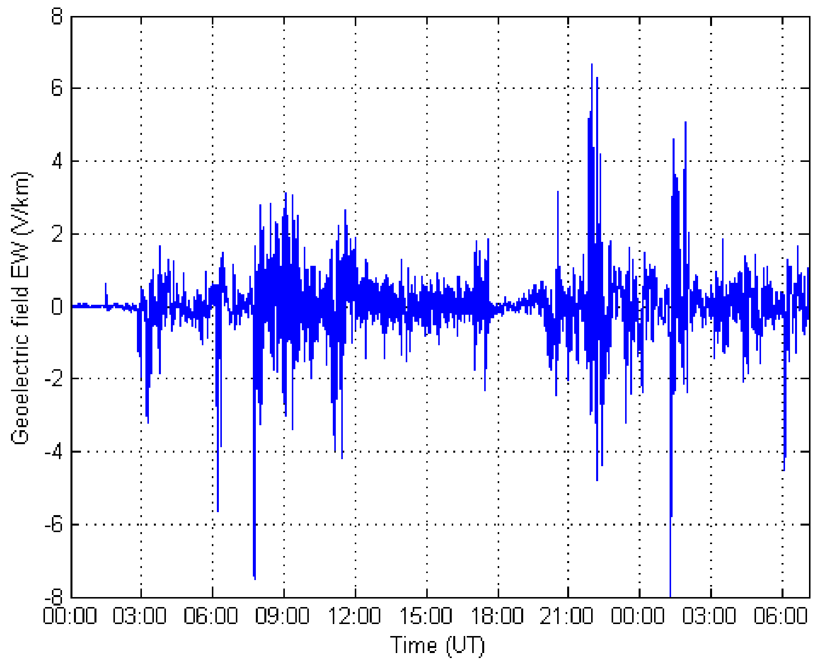


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

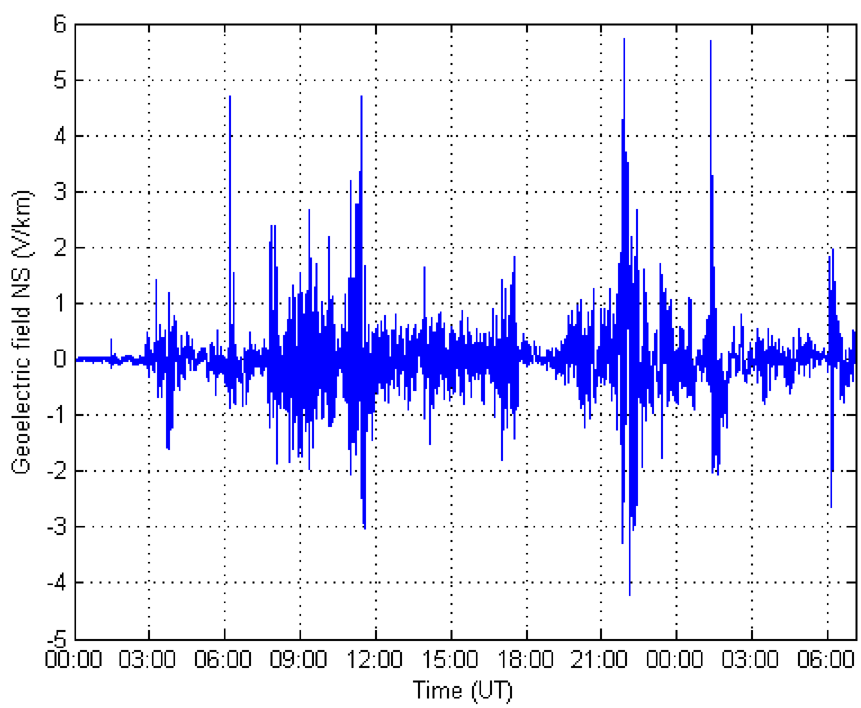


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of pre-1980s events. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available pre-1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. It should be noted that the error bars in such analysis are significant, but it can be concluded that the March 1989 event is, statistically speaking, likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity conductivity features that results in consistently high geoelectric fields (e.g., costal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

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[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that any one area is more likely to experience a localized enhanced geoelectric field.

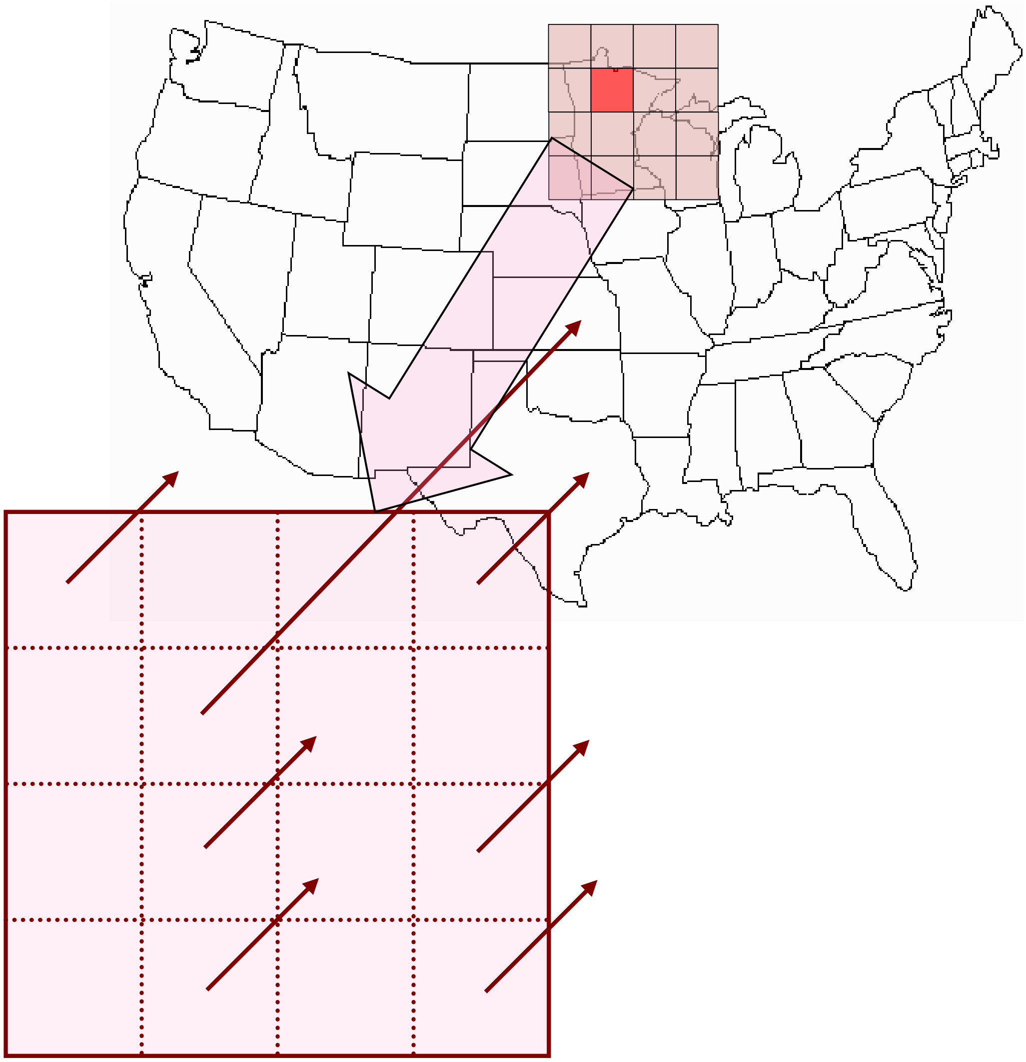


Figure I-1: Illustration of the spatial scale between localized enhancements and larger spatial scale amplitudes of geoelectric field observed during a strong geomagnetic storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterization of GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions from cascading failure and voltage collapse points of view. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process would involve taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km.

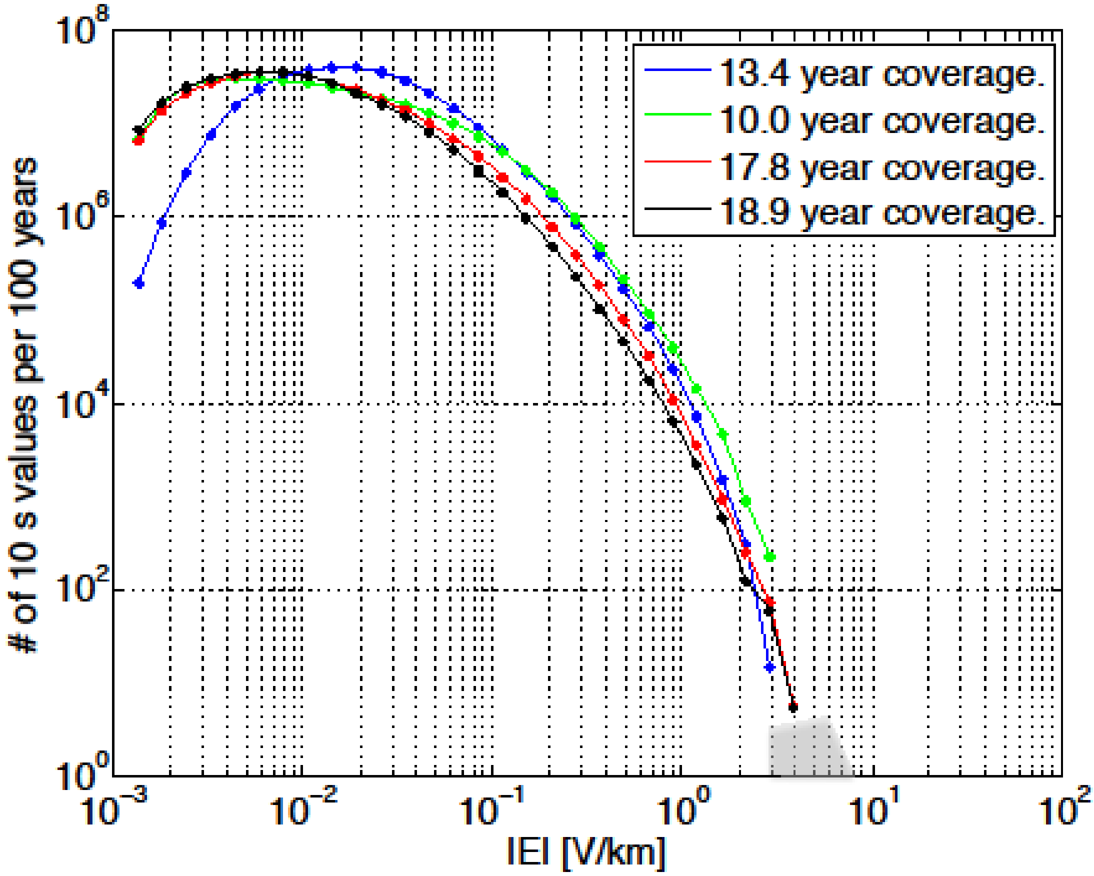


Figure I-2: Statistical occurrence of spatially averaged geoelectric field amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geo-electric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

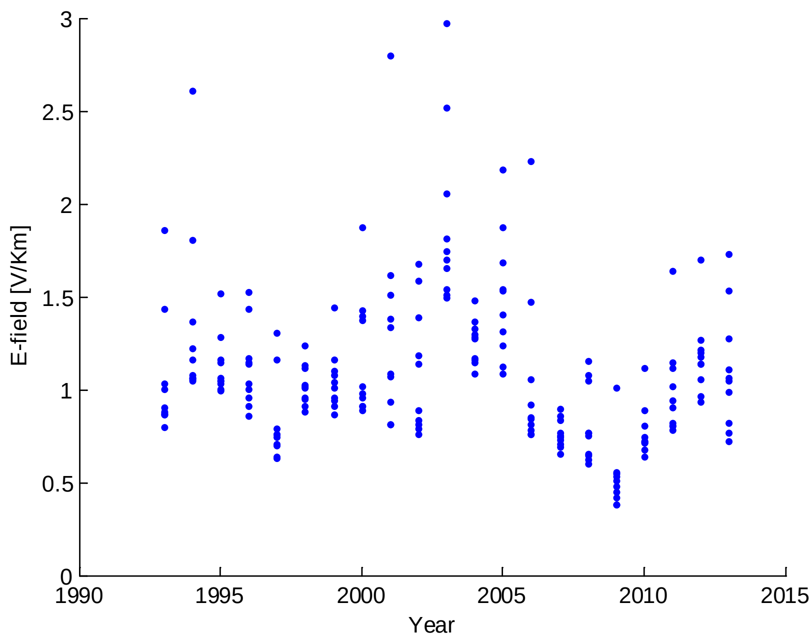


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies

[3] A 95 percent confidence interval means that, if we were to obtain repeated samples, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

on the Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The upshot is an increase in the mean return level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; too low a threshold will likely lead to bias. On the other hand, too high a threshold will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^{*}=\sigma_{u}-\xi \cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistical significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis shows that the geoelectric field amplitude of 8 V/km for the benchmark is conservative for a 100-year return level and it includes an implicit 25 percent safety margin.

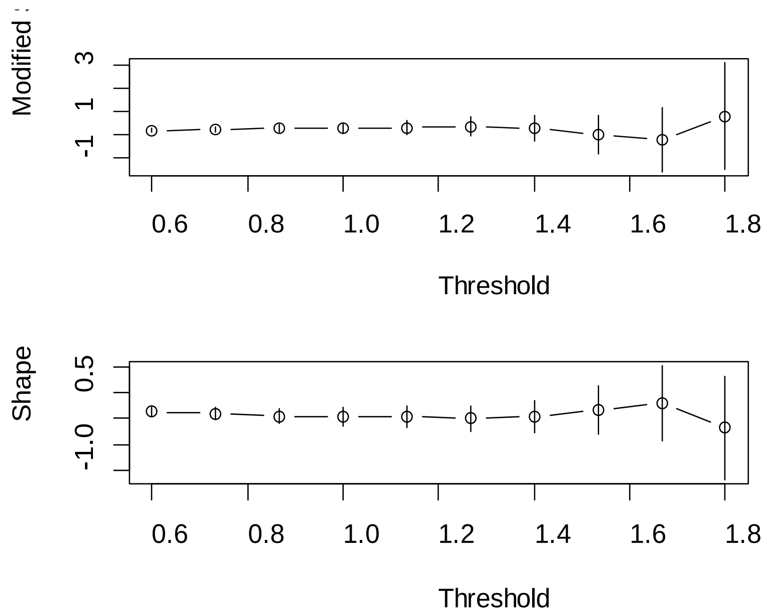


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

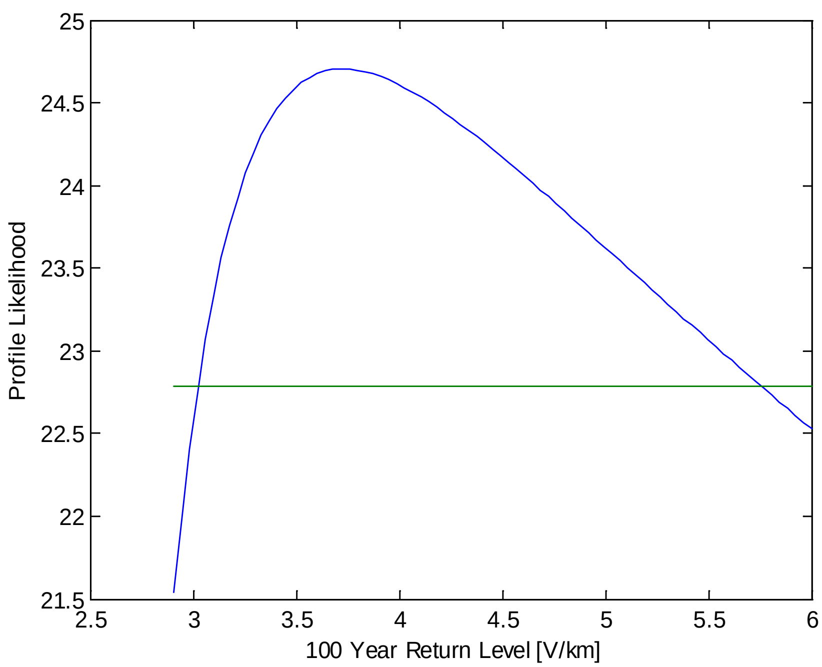


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network was subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and do not warrant further consideration in network analysis.

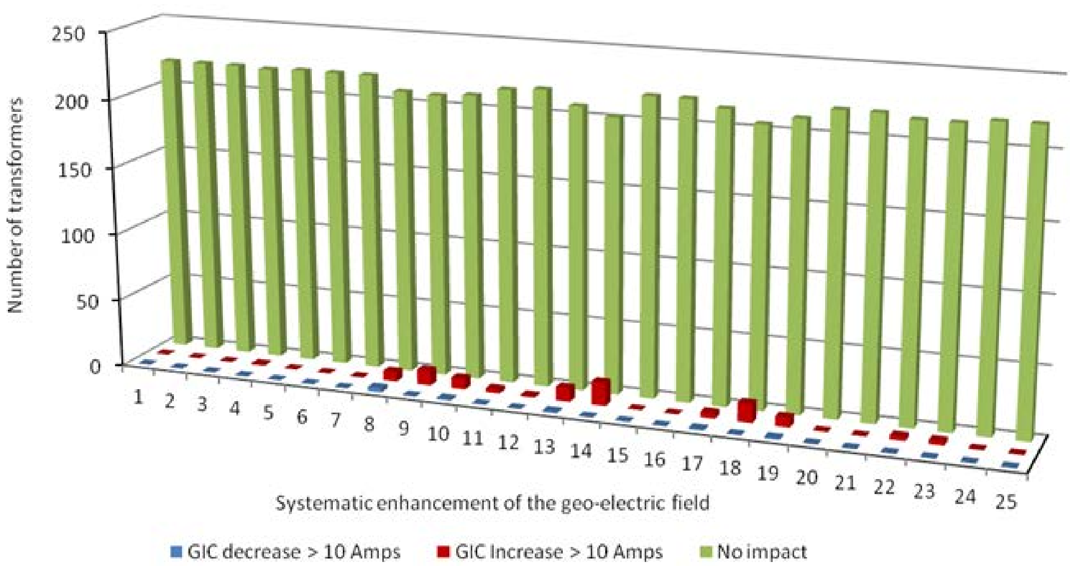


Figure I-6: Number of Transformers That See a 10 A/phase Change in GIC Due To Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such as the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

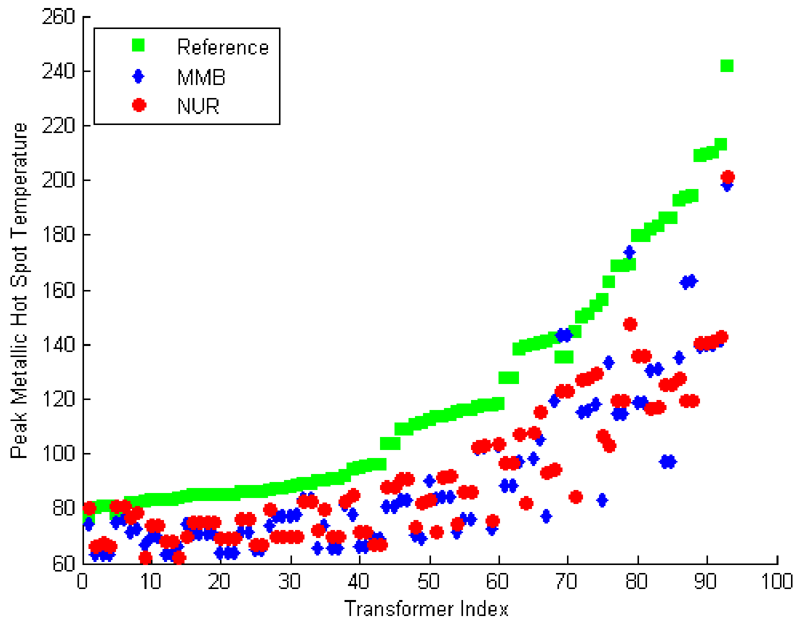


Figure I-7: Calculated peak metallic hot spot temperature for all transformers in a test system with a temperature increase of more than 20°C for different GMD events scaled to the same peak geoelectric field

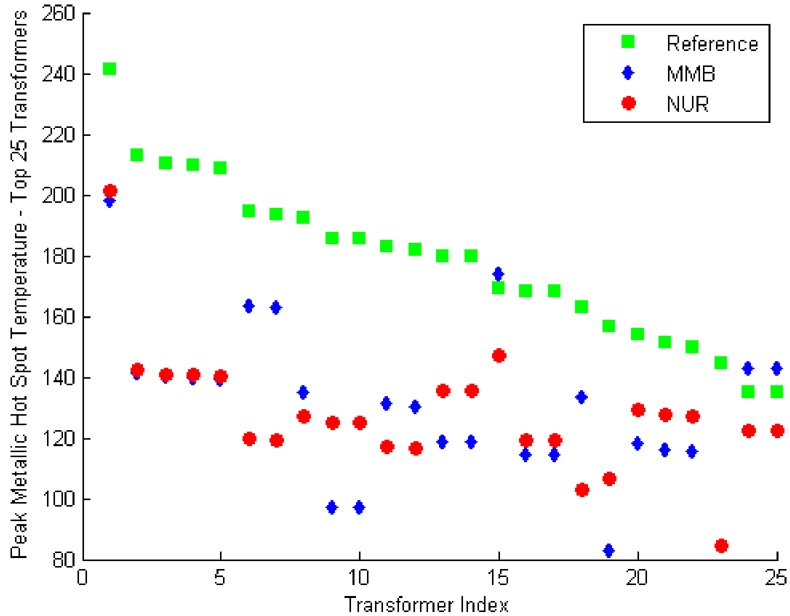


Figure I-8: Calculated peak metallic hot spot temperature for the top 25 transformers in a test system for different GMD events scaled to the same peak geoelectric field

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]. Scaling factors for geomagnetic latitude take in consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** provides a scaling factor correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees

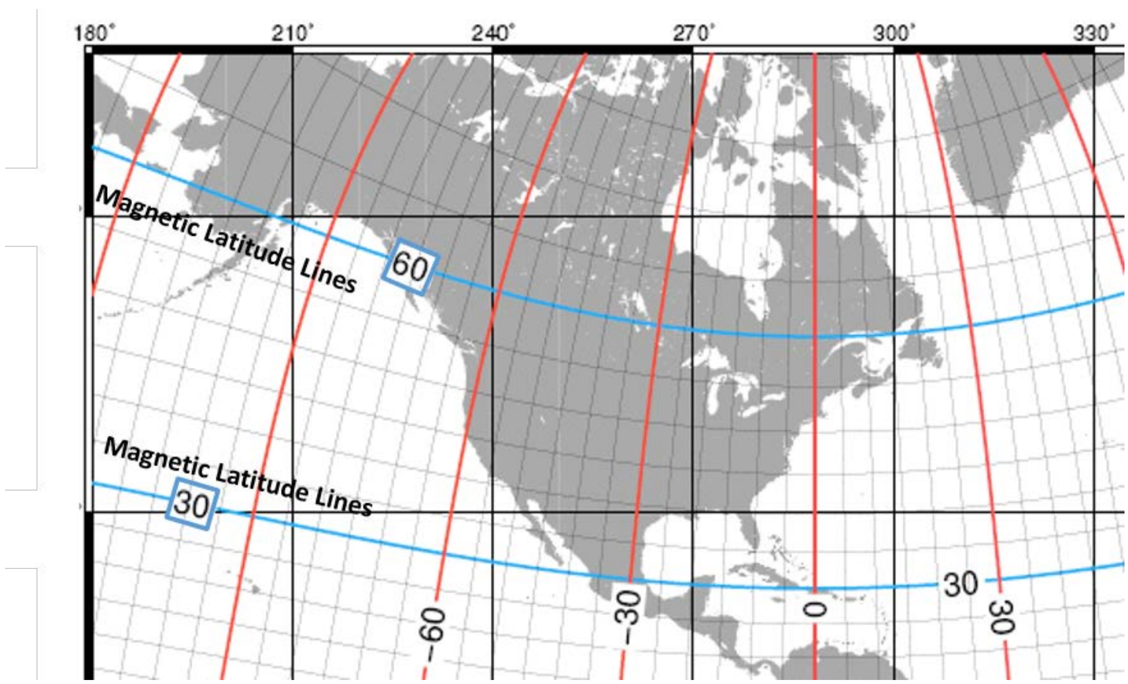


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is with respect to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.
[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
55	0.6
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \tag{II.2}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

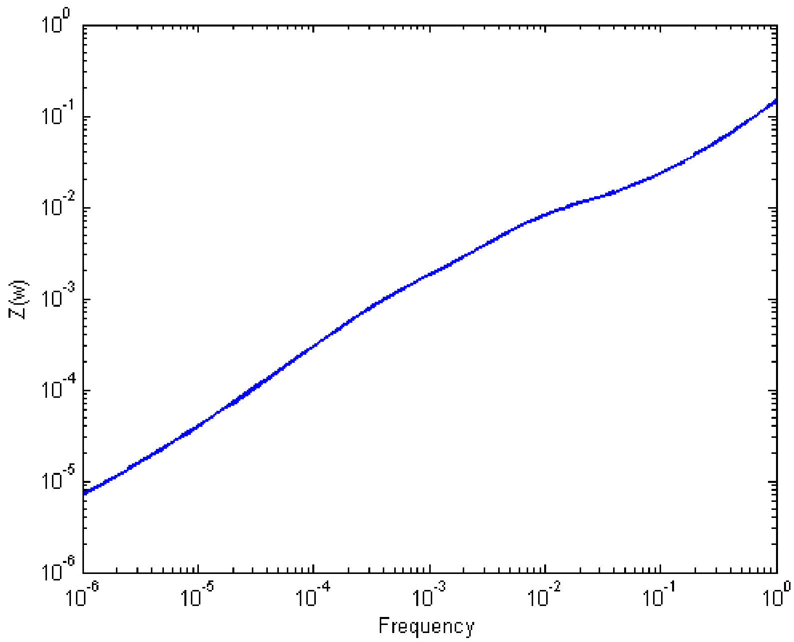


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

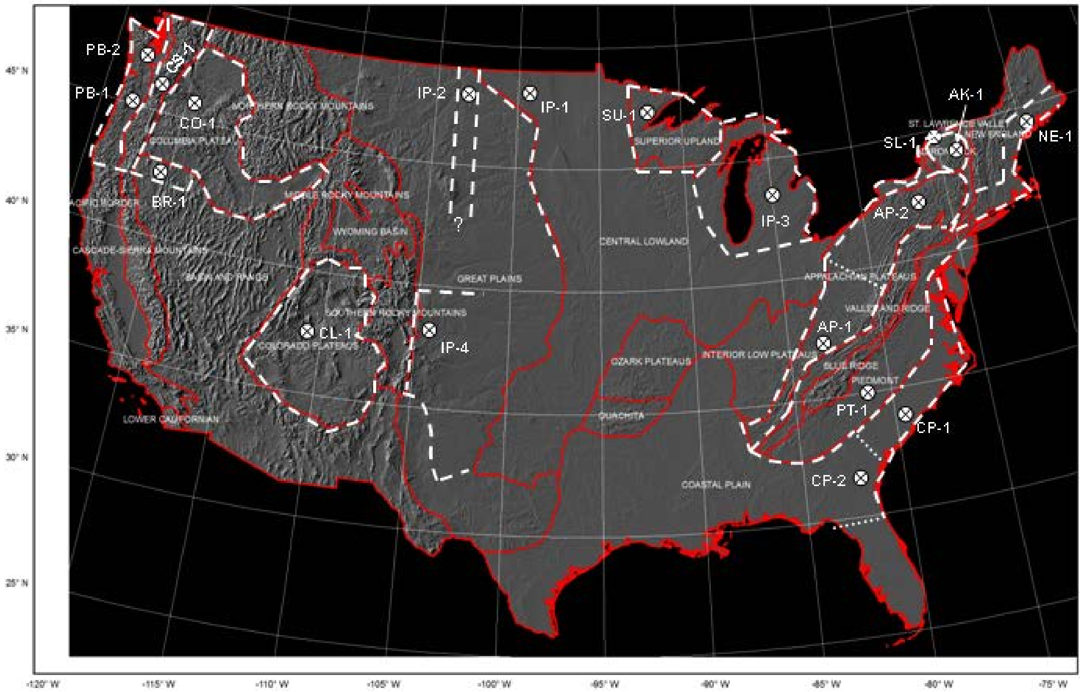
If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States is from magnetotelluric data and is available from the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions these will all be different (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and comprise of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second geomagnetic field recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory of sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

Location of 1D Earth Resistivity Models with respect to Physiographic Regions of the USA



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

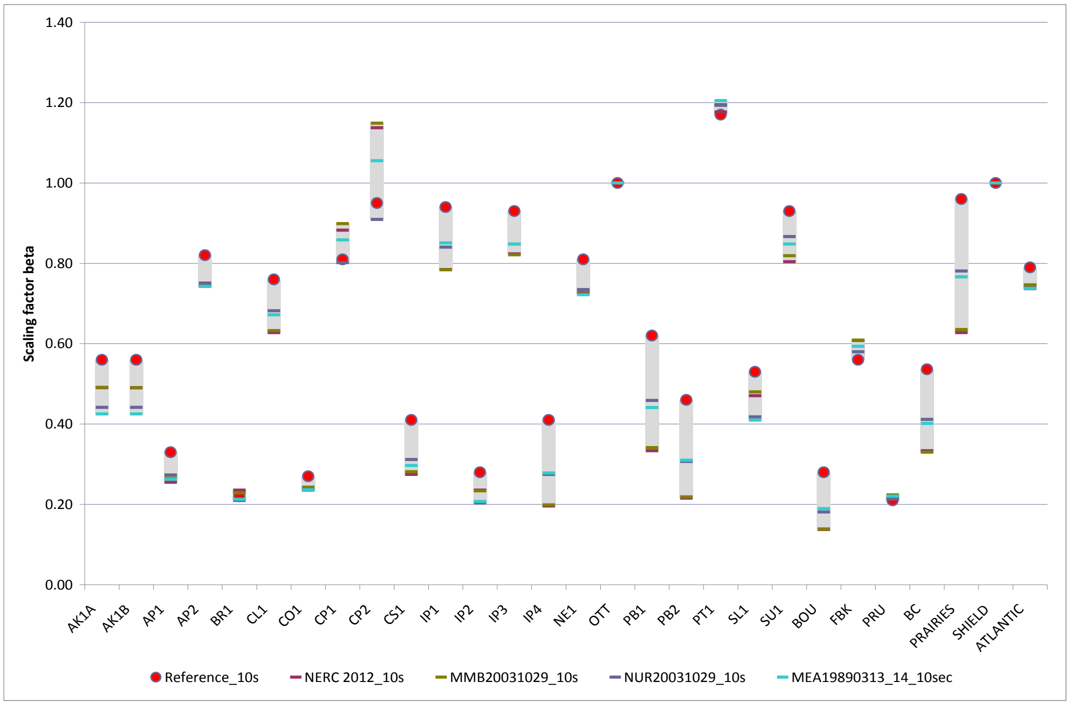


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles corresponds to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α from **Table II-1** is 0.562; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.562$$
$$\beta = 1$$
$$Epeak = 8 \times 0.562 \times 1 = 4.5 \text{ V/km}$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α from **Table II-1** is 0.562; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity that the reference benchmark conductivity, and according to the conductivity factor β from Table II-2. Then:

Conductivity factor β=1.17

$$\alpha = 0.562$$

$$\beta = 1.17$$

$$Epeak = 8 \times 0.562 \times 1.17 = 5.3 \text{ V/km}$$

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper (Draft)

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance during Geomagnetic Disturbances

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. The Stage 1 Standard, EOP-010-1 is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically induced current (GIC), results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

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.

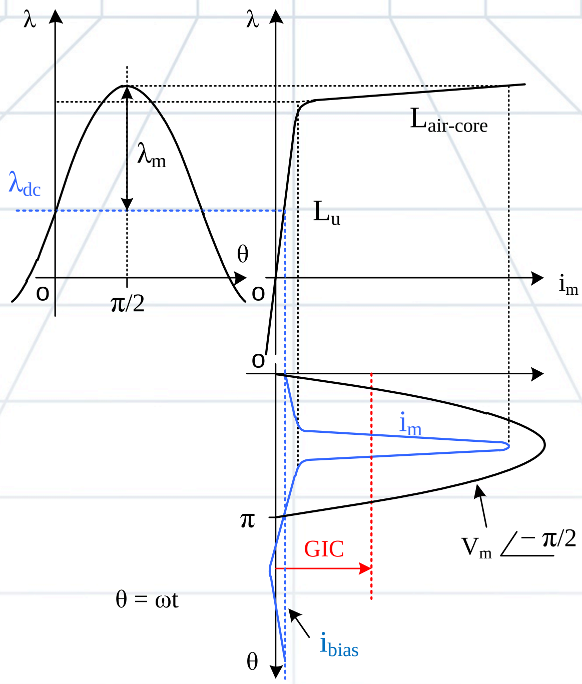


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation, and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.
- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or “waveshape” of the reference GMD event in terms of peak amplitude, duration and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The “effective” GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2]

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \qquad (1)$$

where,

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

There are two different ways to carry out a detailed thermal impact screening:

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers and limited information is available regarding the assumptions used to generate these curves, in particular the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would reach a temperature of 180 °C at full load. 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.

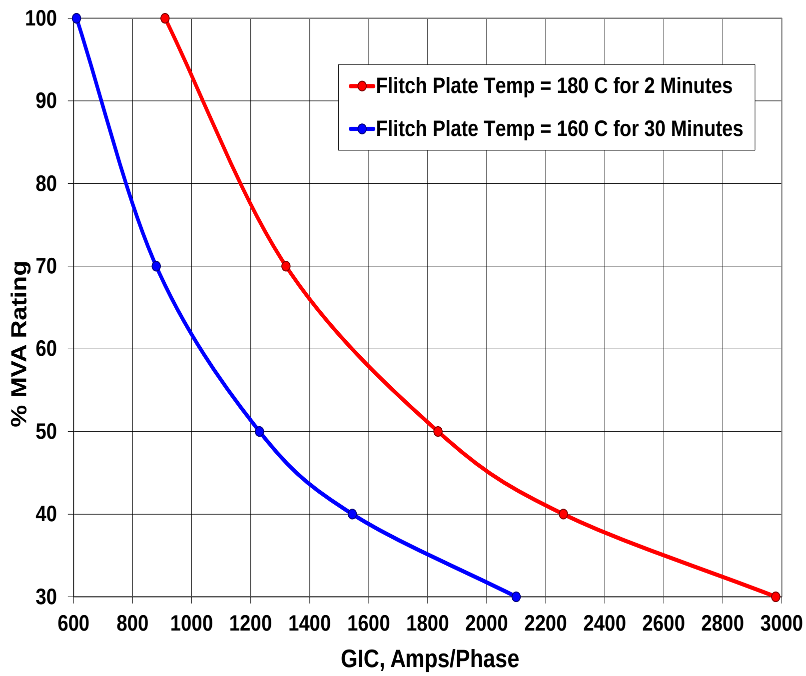


Figure 2: Sample GIC manufacturer capability curve of a large single-phase transformer design using the Flitch plate temperature criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system) and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std. C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

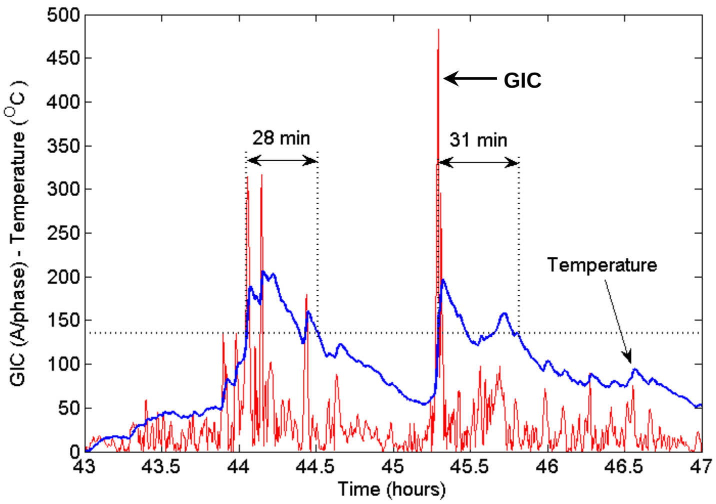


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC waveshape for a transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration

[1] Technical details of this methodology can be found in [4].

2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform Eastward geoelectric field of 1 V/km (GIC_E) while the Northward geoelectric field is zero. Similarly, GIC_N can be obtained when a uniform Northward geoelectric field of 1 V/km while the Eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase/V/km) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \tag{2}$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

GIC_N is the effective GIC due to a Northward geoelectric field of 1 V/km and GIC_E is the effective GIC due to an Eastward geoelectric field of 1 V/km.

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude factor α is applied[2]. Applying (2) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -6A/phase if E_N=0, E_E=1 V/km and GIC_N = 9.6A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore,

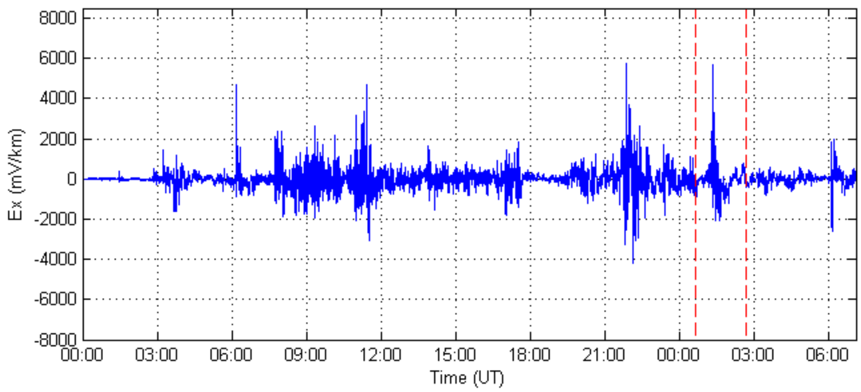
[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator) the lower the amplitude of the geomagnetic field.

$$GIC(t) = \sqrt{E_N^2(t) + E_E^2(t)} \cdot \{GIC_E \sin\varphi(t) + GIC_N \cos\varphi(t)\}$$

$$GIC(t) = \sqrt{E_N^2(t) + E_E^2(t)} \cdot \{-16 \cdot \sin\theta(t) + 9.6 \cdot \cos\theta(t)\}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.



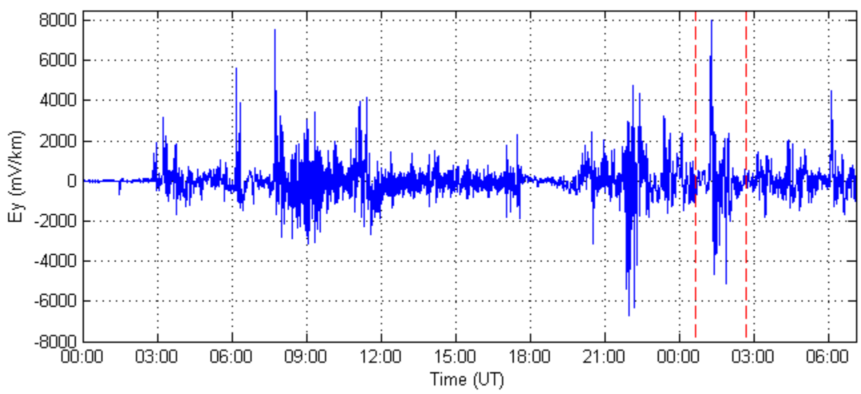


Figure 4: Calculated geoelectric field $E_N(t)$ and $E_E(t)$ assuming α=1 and β=1 (Reference Earth Model)

Zoom area for subsequent graphs is highlighted.

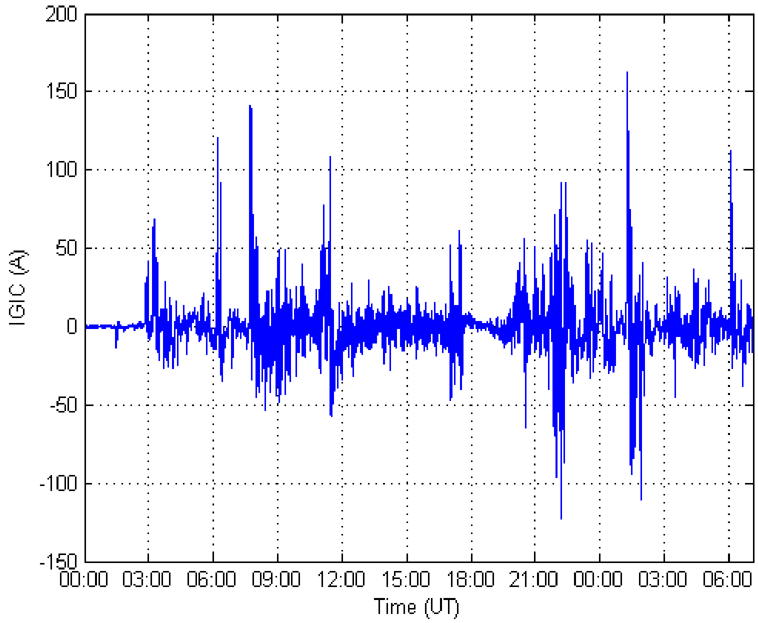


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

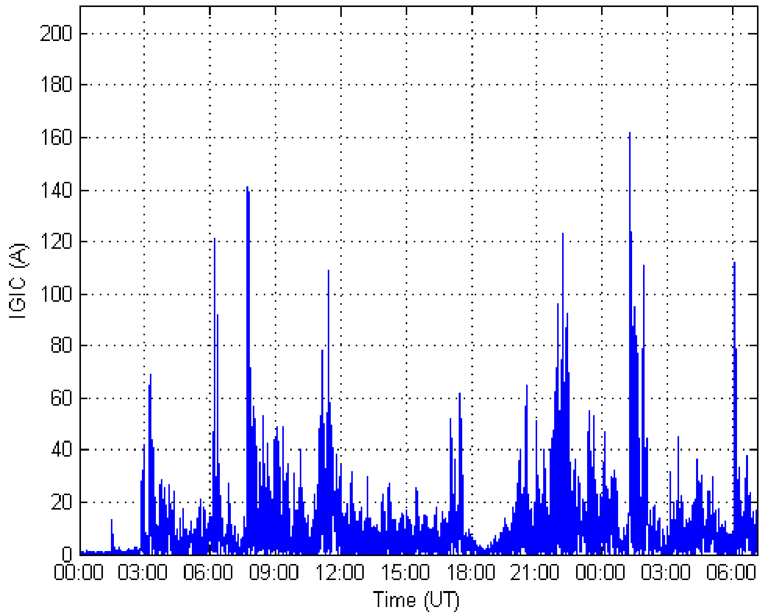


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) using manufacturer's capability curves, and 2) calculating the thermal response as a function of time.

Example 1: Using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: (a) measurements; (b) manufacturer's calculations; or (c) generic published values. **Figure 7** shows the measured metallic hot spot thermal response from [4] that will be used in this example. **Figure 8** shows the estimated incremental temperature rise (asymptotic response) of the hot spot to long duration GIC steps.[3] The asymptotic response in **Figure 8** is extrapolated linearly from relatively low magnitude dc measurements. This is a conservative approximation for illustration purposes. In the Fingrid transformer tests reported in 2002 [6], the measured maximum value of the asymptotic response of the inside of the yoke clamp (highest hot spot temperature) is 15% lower than the value obtained using linear extrapolation. The linear extrapolation results in a calculated temperature peak 9% higher than the measured asymptotic behavior when the GIC(t) time series in **Figure 6** is used.

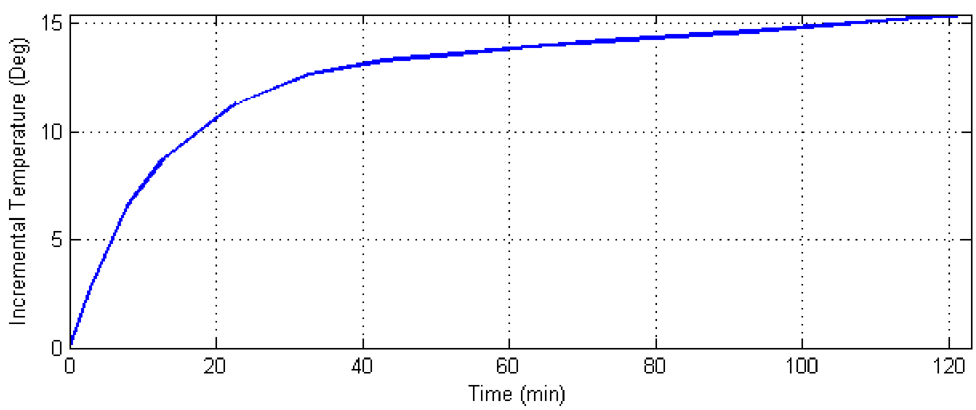


Figure 7: Thermal Step Response to a 5 A/phase dc Step [3]
Metallic hot spot heating.

[3] The heating of the bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

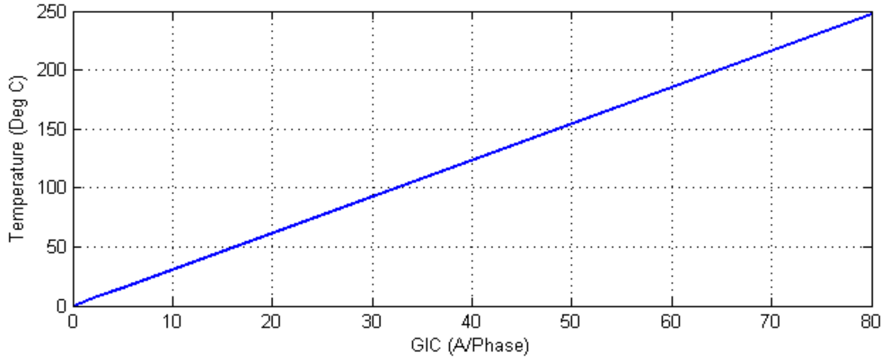


Figure 8: Asymptotic Thermal Step Response [4]
Metallic hot spot heating.

In order to obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time θ(t) for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 9 shows the calculated GIC(t) and the corresponding hot spot temperature time series θ(t). **Figure 10** shows a close-up of the peak transformer temperatures calculated in this example.

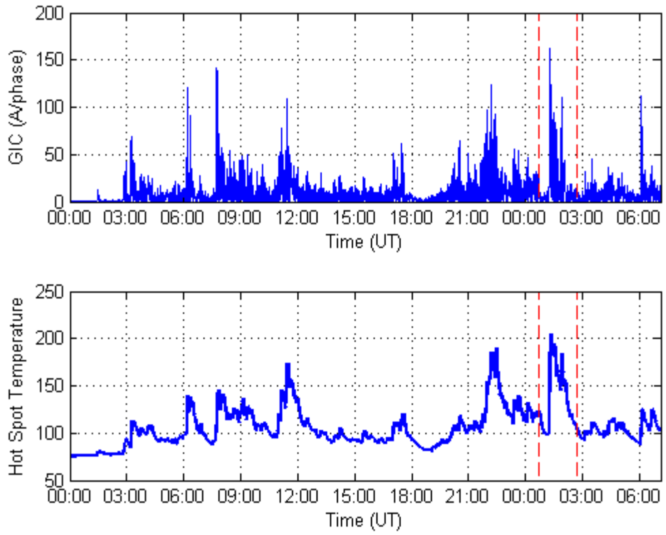


Figure 9: Magnitude of GIC(t) and metallic hot spot temperature θ(t) assuming full load oil temperature of 75.3°C (30°C ambient)

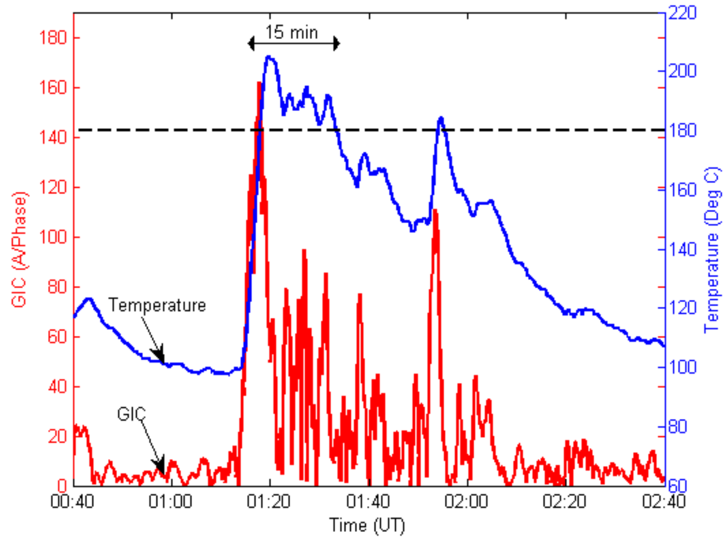


Figure 10: Close-up of Metallic hot spot temperature θ(t) assuming a full load (blue trace)

Red trace is GIC(t)

In this example the IEEE Std. C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is exceeded for 3 minutes (as opposed to 30 minutes for emergency overloading). Peak temperature is 204°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold to account for calculation and data margins as well as transformer condition. **Figure 10** shows that 180°C will be exceeded for 15 minutes.

At 70% loading, the initial temperature is 54.5 °C rather than 75.3 °C and the hot spot temperature peak is 183°C. In this case the 180 °C threshold is exceeded for 2 minutes (see **Figure 11**).

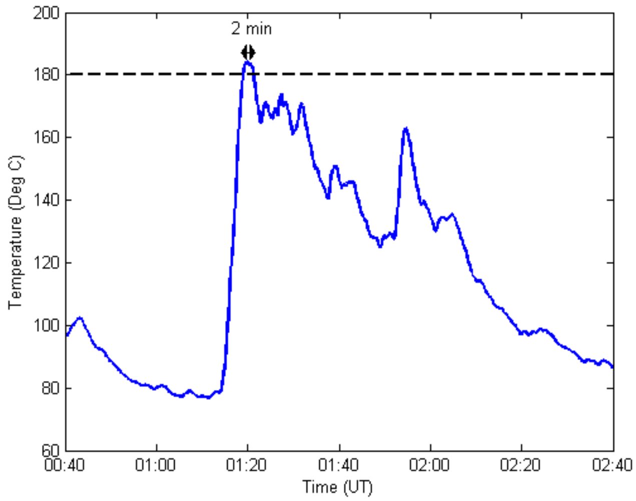


Figure 11: Close-up of Metallic hot spot temperature assuming a 70% load
(Oil temperature of 54.5°C)

Example 2: Using a manufacturer's capability curves

The capability curves used in this example are shown in **Figure 12**. To be consistent with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 8** and **9**, and the simplified loading curve shown in **Figure 14** (calculated using formula from IEEE Std. C57.91).

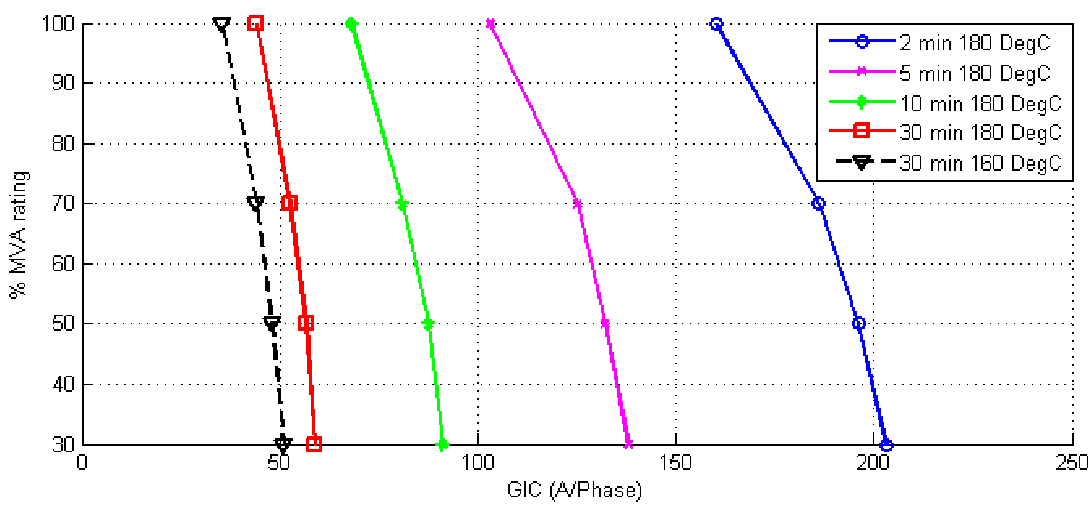


Figure 12: Capability curve of a transformer based on the thermal response shown in Figures 8 and 9

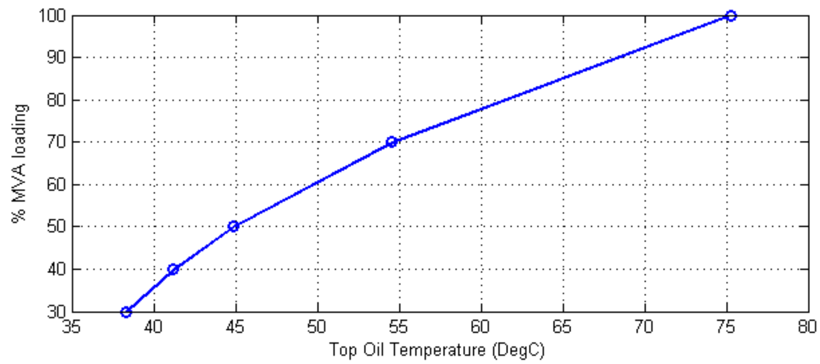


Figure 13: Simplified loading curve assuming 30°C ambient temperature

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve then the transformer is within its capability.

To use these curves it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 14** shows a close-up of the GIC near its highest peak superimposed to a 160 A/phase, 2 minute pulse at 100% loading from **Figure 12**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 103 A/phase at 100% loading has been superimposed on **Figure 15**. It should be noted that a 160 A/phase, 2 minute pulse is equivalent to a 103A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

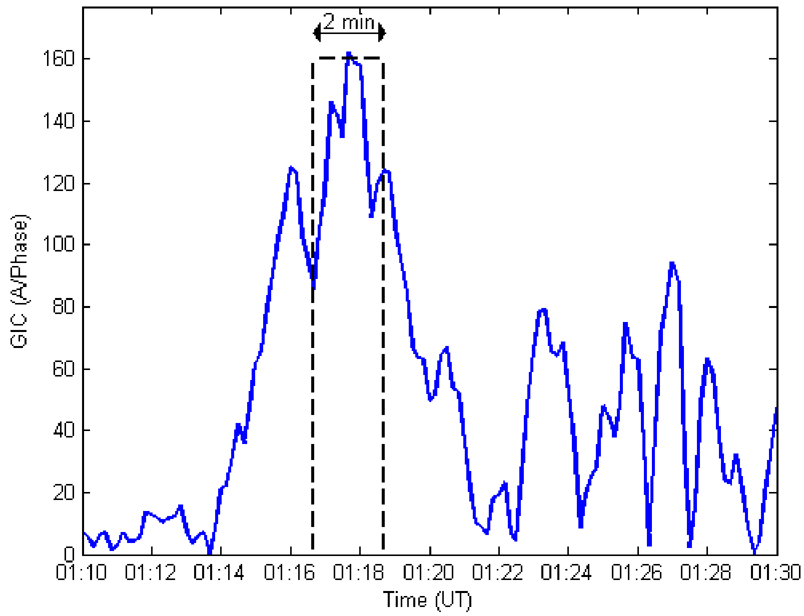


Figure 14: Close-up of GIC(t) and a 2 minute GIC pulse at full load

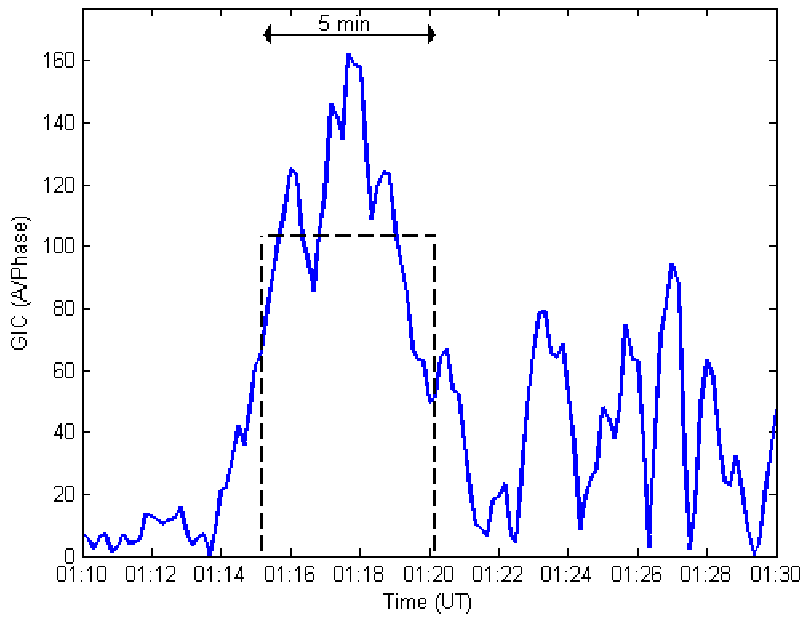


Figure 15: Close-up of GIC(t) and a 5 minute GIC pulse at full load

When using a capability curve it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), allowances have to be made in terms of prior hot spot heating. From these considerations it is apparent that the capability curves would be exceeded at full load with a 180 °C threshold.

At 70% loading, the two and five minute pulses from **Figure 12** would have amplitudes of 186 and 125 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 16**. In this case, it is not easy to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above or clearly below the GIC thresholds for a given pulse duration.

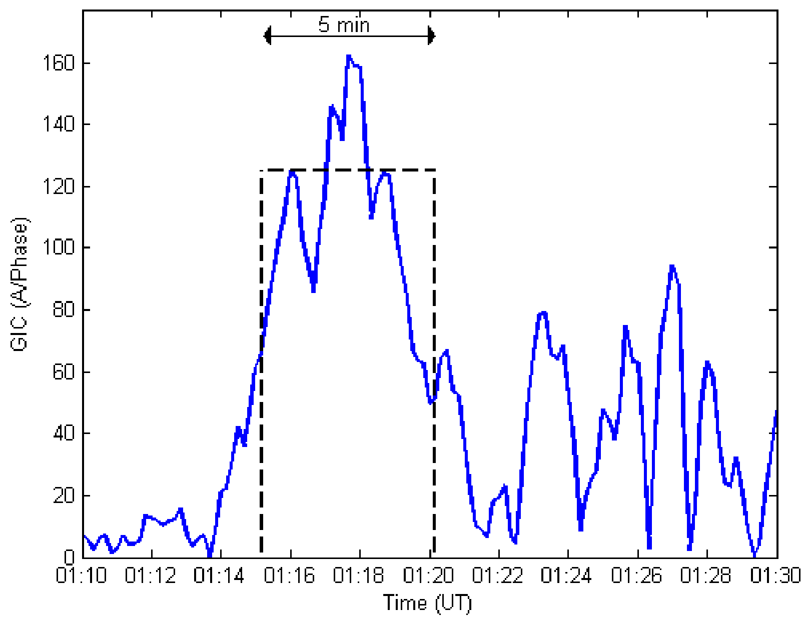


Figure 16: Close-up of GIC(t) and a 5 minute GIC pulse assuming 70% load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1 and Benchmark GMD Event

Informal Comment Period Now Open through May 21, 2014

Now Available

A 30-day informal comment period for **TPL-007-1 - Transmission System Planned Performance During Geomagnetic Disturbances** and **a Benchmark GMD Event white paper** is open through **8 p.m. Eastern on Wednesday, May 21, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

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Individual or group. (61 Responses)
Name (41 Responses)
Organization (41 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (61 Responses)
Question 1 (0 Responses)
Question 1 Comments (54 Responses)
Question 2 (48 Responses)
Question 2 Comments (54 Responses)
Question 3 (41 Responses)
Question 3 Comments (54 Responses)
Question (46 Responses)
Question 4 Comments (54 Responses)

Individual
Reigh Walling
Walling Energy Systems Consulting, LLC
No
I agree that the assessments required by the stage 2 standard meet the assessments directed by the FERC. There are two specific changes in the wording of the standard that I believe will enhance the relevance and value of the assessments: 1. In Requirement 2, Clause 2.1 requires study of peak and off-peak conditions. It is a reasonable generalization that peak load conditions would be a critical condition for which study is justified. Off-peak load conditions may or may not be condition of relative criticality, depending on the characteristics of the specific system. It is suggested that Clause 2.1.2 be modified to require study of either an Off-Peak condition or an alternative condition that is diverse from the Peak condition in terms of generation dispatch, power import or export, reliance on reactive compensation, etc. for which a justifiable basis can be made that the condition might be critical in terms of susceptibility to GMD impacts. The suggested revision retains the requirement to study two different conditions, but avoids the possible waste of engineering resources to study an Off-Peak condition that may obviously be non-critical in some systems. 2. Footnote 2 of Table 1 can easily be misinterpreted to imply that the sole impact of harmonics during GMD is to cause the tripping of BES assets due to misoperation of protection systems. Extreme harmonics during GMD can cause damage to BES equipment such as capacitor units and generators from which the equipment may not be adequately protected by the existing

protection schemes. It is strongly recommended that the wording of footnote 2 be revised to state "Harmonics during GMD may result in tripping of BES transmission and generation assets due to damage to the equipment or due to misoperation of protection systems. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible."
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Once a PC or TP is chosen as an applicable functional entity, it is not specified on which facilities of the system the modeling Requirement R1 and the study requirements (R2, R3 and R7) shall apply. Not all facilities should be included in the studies; only those having a significant impact.
No
The P8 event in Table 1 doesn't offer enough clarity. We would expect that the "GMD event" is not an initial condition, but is part of the event. It would be needed to explain the nature of this event: is it the increase of dc current on the system and the transformer saturation? How is an entity going to simulate this event that leads to the removal of compensating devices or Transmission Facilities? These points need to be clarified before the standard can be approved. The benchmark GMD Event is a new approach that needs to be well mastered before being adopted. Refer to our response to Question 4. It is indicated in the Purpose that the requirements are within the Near-Term Transmission Planning Horizon. However, specific requirements (R1 to R8) refer to a Long-Term Planning Horizon. Delete the Time Horizon reference in the Purpose to avoid confusion.
No
GMDs cover large geographical areas, so it’s very important to have modelling data from neighboring regions, especially in the congested Northeast, in order to identify impacts from external equipment. How does the Drafting Team envision ensuring that actions taken in one area do not negatively impact entities in adjacent areas? For example, PJM CAP negatively affecting NYISO entities. For example, a PJM CAP might result in GIC’s flowing on adjacent NYISO elements exacerbating the problem in New York. What recourse would an adjacent region have to prevent this negative impact from shifting GMD related costs to their region? There is concern with the Benchmark GMD Event proposed in Attachment 1 and the high value of the geoelectric field of 8 V/km not being based on direct measurement, but on hypothesis to deduce electric field from magnetic field. For example, according to the proposed method and the field scale, the top value would be applied to a large portion of Québec, with much higher values than those applied to most of the United States. Hydro-Québec did experience the March 1989 GMD, but the electric field deduced from that event

was much less than the proposed value of 8 V/km. It should be considered that the direct reading of electric field should be in the methodology. Historical records are most representative of the risk that entities have to face. Also, it should be considered that this is a new method of analysis and it needs to be validated before requiring compliance based on those estimated values. Parts 2.2 and 7.1 specify the Benchmark GMD event described in Attachment 1 be used in the GMD Vulnerability Assessment and assessment of thermal impact. During the Project 2013-03 Geomagnetic Disturbance Mitigation Industry Webinar on April 24, 2014 it was stated that the benchmark event does not need to be used, but if an entity used something different they had to provide an explanation/justification. Clarification is needed.
No
Throughout the standard, the acronym for alternating current should be capitalized AC. As in other standards, acronyms for terms not used in the NERC Glossary are capitalized. Geomagnetically induced current contains both AC and DC components. Are AC models adequate to capture the impact of a geomagnetic disturbance? The Rationale Box for R1 supports the importance of DC models. The Geomagnetic Disturbance Planning Guide, December 2013 discusses DC system models. If a DC model is needed, then requirement R1 should be made to read: R1. Each Planning coordinator and Transmission Planner shall maintain alternating current (AC) and direct current (DC) System models…. Regarding the Table 1 footnotes, Footnote 1 simply repeats the initial condition statement, but should be expanded to provide examples. Each category of the Implementation Plan allows a time delay of one year after completion of the preceding stage: 1) System modeling, 2) Vulnerability assessments to GMD events, 3) Assessment of thermal impact on power transformers, 4) Corrective action plan. This Implementation Plan is highly dependent on the availability of time study tools. Please make sure that sufficient delay for tool development is considered and that stages are postponed accordingly. Given the newness of the science and assumptions, it is possible that more time than four years may be needed. If models or other factors change as the science develops, latitude should be offered with respect to the four year implementation plan. The standard would be easier to understand if R5 were combined with R2. The PC/TP obligation for conducting the GMD Vulnerability Assessment and the responsibility of the PC to determine the split of responsibilities between the PC/TP for conducting the GMD Vulnerability Assessment should be in the same Requirement. As written, R2 requires each Planning Coordinator and Transmission Planner to complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. R5 states that “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator’s area for performing the required studies for the GMD Vulnerability Assessment.” The standard refers to the Corrective Action Plan in R1 and M1. However, the Corrective Action Plan is described in R3. We suggest revising the reference in R1 to “the Corrective Action Plan developed under R3.” We think the benchmark GMD event is technically justified (but it must consider real life measurements [see response to Question 3]), and provides the necessary basis for conducting the assessments directed in Order No. 779. Regarding R2, why does the standard categorize it as

a “Long-term Planning” horizon? The Parts and sub-Parts state that the study conditions should include peak load “…for one year within the Near-term planning horizon”? Requirement R4 may conflict with the requirements of other TPL standards. The Rationale for Requirement R4 refers to TPL-001 and, accordingly this should be explicitly referenced in the requirement. Regarding R6 and M6, the distribution of results should be limited to other entities (TO/GO) only to the extent those TO/GOs need the specific study results. This approach limits distribution of CEII and focuses the release of study results to pertinent other parties. Recommend that distribution of the GMD Vulnerability Assessment be clarified and limited with wording such as “…shall distribute results to relevant TOs and GOs in its respective planning area and, as appropriate, adjacent PCs and TPs.” R6 requires distribution of results to “…any functional entity that has a reliability related need…” but does not specify what constitutes a reliability related need. The distribution of study results should be limited to protect CEII. R6 does not indicate what the TOs, GOs and adjacent PCs and TPs should do with the GMD Vulnerability Assessment results. Measure M6 should include reference to distribution of results to TOs and GOs. Requirement R7 should refer to the GMD Vulnerability Assessment results that were distributed to the TO and GO as specified in R6. Requirement R8 requires TOs and GOs to provide transformer assessments to PCs and TPs but does not specify what the PCs and TPs should do with the information. The SDT should consider including a requirement about what the PC and TP should do with this information.
Group
FirstEnergy Corp.
Richard Hoag
In general FirstEnergy Corp. agrees with the drafting team. The Planning Coordinator is required to keep a model and would need inputs from the Generator Owner, however, geomagnetic disturbances are a low probability impact for generators.
Yes
The drafting team assembled a good flexible standard.
Yes
Yes
The implementation timeline is realistic as written and should not be shortened.
Individual
John Seelke
Public Service Enterprise Group
While we agree that the correct functional entites have been identified, we have concerns that R3 and R6 allow a PC or TP to specifiy what a TO or GO must do in a CAP. We assume that CAP developed in R3 and commented on in R6 would assign responsibilities for mitigation to TOs and GOs, even though R3 does not explicitly assign them mitigation responsibilities. The first two bullets of R3 (shown below) could greatly impact TOs and GOs:

• Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. We offer three points for the SDT to consider: • TOs and GOs cannot be delegated mitigation obligations by a PC/TP under the NERC framework. While "performance" can be dictated by a NERC standard, how that performance is achieved (the "what") cannot be. • A PC/TP CAP should require all impacted TOs and GOs to concur with the it. Only by such concurrence can TOs and GOs acknowledge their GMD mitigation responsibilities. o Alternatively, the PC/TP Vulneability Assessment in R2 could require location-specific performance for GMD, with the development of a CAP required by the associated TOs and GOs to meet that performance. • The requirements R2 and R3 which, in part, state "Each Planning Coordinator and the Transmission Planner shall …" would be interpreted to mean both the PC and the TP shall perform the required action. If a GO has a different PC and TP, this may result in two CAP plans. We understand that this is not the intent, but we recommend that the SDT consider this wording: "Each Planning Coordinator, or its designated Transmission Planner, shall…"
No
The sequence of events required by TPL-007-1 is not communicated in the standard. We recommend a flow diagram or a Gantt chart be provided in an attachment to the standard to indicate the sequence of requirements and the compliance timing for each requirement, along with a brief explanation of the logic of the sequence. We note that the Implementation Plan requires this order of implementation by various entities, with the cumulative time (per the Implementation Plan) for compliance with different requirements from the date pf regulatory approval of TPL-007-1: • R1 and R5 are performed first by the PC/TP. (12 mo.) • R2, R4, and R6 are performed second by the PC/TP. (24 mo.) • R7 and R8 are performed third by the TO and GO. (36 mo.) • R3 is performed last by the PC/TP. (48 mo.) It is difficult to understand how the GMD Vulnerability Assessment required in R2 can be completed without understanding whether R7 thermal impacts may result in need for temporary removal or other mitigation means for TO or GO transformer assets. In addition, R6, which allows other Transmission Planners as well as TOs and GOs to comment on Vulnerability Assessment the CAP, cannot be completed before R3 (the development of the CAP) is completed.
No
The benchmark GMD event is so severe that even new transformers specificed at locations that have experienced a prior GMD event and whose owners are aware of Order 779 will likely require mitigation under TPL-007-1.
No
The allotted time for GOs and TOs to complete the assessments specified in R7 is insufficient. Firstly, on the assumption that TOs and GOs receive the GIC information required to complete R7 on time – by 24 months after applicable authority approval - from the PC/TP, 12 months (36 – 24) to complete R7 will be inadequate. Secondly, there is no allowance in the plan for GOs and TOs in the event the PC/TP does not provide the GIC information at the 24 month milestone. The implementation plan needs revision to provide a specified amount of time to

TOs and GOs after receipt of the GIC information from the PC/TP. And the specified amount of time must be treater than 12 months; PSEG suggests 24 months.
Individual
Terry Volkmann
Volkmann Consulting, Inc
FERC Order No. 779 (P.67) requires the development of one or more standards that requires the owners and operators perform vulnerability assessments. TPL-007 falls short in meeting this FERC directive. Earlier the NREC BOT adopted EOP-010 that requires the RC & TOP to develop operating procedures with no requirements for conducting vulnerability assessments. TPL-007 is developed as a Planning Standard with: 1. no requirement for the PC and TP to communicate the vulnerability assessment results to the applicable RC and TOP. 2. no requirement for the RC and TOP to integrate the TPL-007 vulnerability assessment findings into their operating procedures under EOP-010. Secondly TPL-007 does not cover the variety of operating conditions that the RC and TOP routinely operate under. As example high transfers were demonstrated to change the voltage collapse point by 50 to 70% in the PowerWorld studies were presented at the NERC GMDTF meeting in March 2014. Since the primary operational step in many of the RC operating procedures is to reduce or maintain transfers under a certain value, it is critical for the RC and TOP to study the effects of power transfers on voltage collapse in their area during a GMD event. Either TPL-007 needs to be expanded to cover operating conditions, i.e. high transfers or a revision to EOP-010 needs to be developed in parallel to require the RC and TOP to conduct vulnerability assessments using similar tools as those developed to meet TPL-007. Finally there are numerous technical articles discussing the development of harmonics during a GMD event and the associated impact on reactive devices (capacitors) and generators. The only connection to harmonics impacts in the TPL-007 standard is the footnote on page 5 in the P8 table. This footnote requires the consideration of equipment outages from harmonics. As stated, this presents three problem areas: 1. the footnote states a requirement to the planner to remove equipment susceptible to harmonics. This should be an explicit requirement directed to the PC or TP. 2. PCs and TPs are not required to have protection system expertise in the course of performing their duties, thus have no foundation to assess protection system susceptibility. This requirement should be assigned to the GO and TO who own the protection system and equipment being protected. 3. The standard requires the TO and GO to evaluate their transformer performance during a GMD event, but not their protection systems. The TO and GO are the owners of the BES protection systems and have access to protection system expertise. It is recommended to add a requirement for the TO and GO to evaluate the vulnerability of their associated capacitor and generator protection systems to harmonics in both relay operability and settings. The TO and GO are then required to provide their assessment of which protection systems are vulnerable to tripping from harmonics during a GMD event to their RC, TOP, PC and TP. Standards C50.12 and C50.13 can provide the basis for the vulnerability assessment of the protection system settings and performance during

the stator harmonic currents that may create rotor heating. The SDT is recommended to develop a guidance document to assist in determining harmonic susceptibility.
No
FERC Order No. 779 (P.67) requires the development of one or more standards that requires the owners and operators perform vulnerability assessments. TPL-007 falls short in meeting this FERC directive. EOP-010 that requires the RC & TOP to develop operating procedures with no requirements for conducting vulnerability assessments. TPL-007 is developed as a Planning Standard with no requirement for the RC and TOP to integrate the vulnerability assessment findings into their operating procedures under EOP-010. Either TPL-007 needs to be expanded to cover operating conditions or a revision to EOP-010 needs to developed in parallel to require the RC and TOP to conduct vulnerability assessments using similar tools as those developed in TPL-007. The following changes should be made: 1. R2 needs to be run at firm transfer and at peak transfer levels in order to fully and accurately assess the vulnerability 2. R2 results need to be communicated to the RC/TOP (could be covered in R6) 3. R3.1 Operating procedures need to be demonstrated to be capable to be executed in the lead times of GMD event notifications. 4. R4 RC and TOP must use same voltage criteria for the same area of study and share limits with adjacent PCs and TPs. 5. R6 90 days is too long to provide the results.
No
FERC Order No. 779 (P.2) requires the benchmark GMD events to be "technically justified". The GMDTF has introduced a concept of spatial averaging with a minimal peak area and has not provided the technical justification of the size of this area. This concept completely ignores the impact in the peak field area of interest. Even if the concept of spatial averaging is correct, there is no basis that the peak area will be restricted to 100 km square. The use of a 30 hour period for the benchmark event is questionable when there is evidence that the Carrington event lasted much longer and may have lasted as long as 12 days. In addition the SDT has not considered that peak areas will move around. Considering the field area will move, the event maybe longer than 30 hours and the peak area of interest may be larger, it is possible that the entire BES between geomagnetic latitudes 60 and 40 degrees will witness peak fields. TPL-007 should require the studying of the area of peak field to understand the vulnerability. The technical justification for the 100km peak area needs to be provided in the Benchmark Geomagnetic Disturbance Event Description document.
Yes
Individual
Scott Knewasser
FRCC
The applicability section of the standard includes power transformers with a high side, wye-grounded winding connected at 200 kV or higher. I believe the intent of the standard is to apply to transformers connected to 200 kV or higher systems. As written, a 230 kV high side,

wye-grounded transformer would not apply since its winding is connected at 230 kV divided by the square root of 3, or 133 kV (line to ground). If the SDT intends to include these transformers, consider revising the applicability section of the standard to include power transformers with a high side, wye-grounded winding connected to 200 kV or higher systems (line to line).
Group
Foundation for Resilient Societies
Thomas Popik
No, we do not agree that applicable functional entities should be limited to “Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater.” First, a lower limit of 100 kV per the Bulk Electric System definition, not a limit of 200 kV, should apply. GMD impacts have been observed in equipment operating between 100 kV and 200 kV, according to the report of the Oak Ridge National Laboratory, “Geomagnetic Storms and Their Impacts on the U.S. Power Grid.” Second, Balancing Authorities and Reliability Coordinators should also be included as applicable functional entities, because these entities must manage GMD impacts and system restoration if planning and installation of hardware protective devices were to be inadequate.
No
No, we do not agree that the proposed standard meets the assessment parameters directed by FERC, principally because the Benchmark GMD Event has not been technically justified. In Order 779, FERC directed that “The benchmark GMD events must be technically justified because the benchmark GMD events will define the scope of the Second Stage GMD Reliability Standards (i.e., responsible entities should not be required to assess GMD events more severe than the benchmark GMD events).” Moreover, we do not agree that the proposed standard adequately takes into account “the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment” as directed by FERC. One “condition” or “technical specification” of equipment would be resistance to mechanical shock and vibration. Yet the proposed NERC standard completely ignores the potential impact of shock and vibration, despite the observation of these effects in equipment during solar storms. Importantly, there is no necessarily long time constant for damage from shock or vibration—a brief peak GIC occurring during sudden storm commencement could immediately damage transformers. The thermal models of transformers proposed for conducting assessments do not present test results and therefore are speculative. Given the opportunity to test a wide variety of transformers for thermal impact and publicly disclose the results, the electric utility industry declined to do so.

No
No, we do not agree that the proposed Benchmark GMD Event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779. The Benchmark GMD Event suffers from the following technical deficiencies: 1. The proposed Benchmark GMD Event proposes a maximum geoelectric field of 8 V/km based on “spatially averaged geoelectric field amplitudes,” a newly contrived, unpublished, and unsupported scientific hypothesis. We took the time to read the published references where available online. Some of the published references appear to contradict the central premise of the proposed Benchmark GMD event. For example, Reference 17 states in its Abstract: “By using GIC data and corresponding geomagnetic data from north European magnetometer networks, the ionospheric drivers of large GIC during the event were identified and analyzed. Although most of the peak GICs during the storm were clearly related to sub storm intensifications, there were no common characteristics discernible in substorm behavior that could be associated with all the GIC peaks. For example, both very localized ionospheric currents structures, as well as relatively large-scale propagating structures were observed during the peaks in GIC. Only during the storm sudden commencement at the beginning of the event were large-scale GICs evident across northern Europe with coherent behaviour.” The published reference reveals that “relatively large-scale propagating structures were observed during the peaks in GIC” and sudden storm commencement has produced “large-scale GIC evident across northern Europe with coherent behaviour”—both statements in clear contradiction of the NERC “spatial averaging” hypothesis which proposes that all high amplitude effects would be localized. 2. Most of the published references used to purportedly support the NERC hypothesis of “spatial averaging” use data from Europe instead of North America. 3. The sparse and selected data used to calculate the NERC benchmark geoelectric field was recorded from 1993 to 2013, a narrow period lacking severe or even moderate solar storms. To develop probabilities for a “100 year” storm peak amplitudes, the widest possible window of prior data should be used, even if the data is from different sources; arbitrary statistical inclusions and exclusions should not trump use of all relevant data sets. 4. The sparse and selected data used to calculate the NERC benchmark geoelectric field was from “four different station groups spanning a square area of approximately 500 km in width.” The safety of the American and Canadian public should not depend on calculations based on data from only four relatively small areas. The location of the four station groups was not disclosed by NERC. 5. The Benchmark GMD Event does not incorporate safety factors, despite its reliance on an untested hypothesis and sparse data. Given the significant societal impact for an erroneous Benchmark GMD Event, (i.e., potential death of millions of Americans and Canadians), use of safety factors would be prudent and should be required. A broad “safety factor” is an essential component of the required design of a Benchmark GMD Event. Moreover, the urgency of a safety factor is elevated by the exclusion of Generator Operators (GOs) from the NERC Standard EOP-010-1 — Geomagnetic Disturbance Operations. If the Phase II Benchmark Event is set too low, it is foreseeable that most electric utilities that implement the hardware protection standard will opt out of purchase of neutral ground or other hardware to protect Generator Step Up transformers at Bulk Power System generation sites. Hence, in a geomagnetic storm comparable to the New York Central Railroad storm of

May 1921, with volts/km far in excess of the 8 V/km benchmark in the proposed standard, hundreds of GSU transformers may be both hardware-unprotected and exempted from participation in mandatory "operating procedures." The combination of jurisdictionally-defective operating procedures and an imprudently low Benchmark Event will leave these long replacement-time transformers without protection and beyond the capability of the President of the United States to order immediate de-energizing of these vulnerable transformers during a storm. Deficiencies in both the GMD operating procedure standard (now under FERC review) and the GMD Benchmark Event should not be allowed to exacerbate risks of a blackout in which over 100 million Americans are without power for 1-2 years.
No
No, we do not support the approach taken by the drafting team in the proposed Implementation Plan because the assessment procedures rely on a flawed Benchmark GMD Event and are otherwise technically deficient. We note that in June 2013 the NERC Standards Committee eliminated a standards project for equipment monitoring that could have provided near-real-time reporting of GIC events and correlation with high voltage transformer operating condition. We urge NERC to develop and make publicly available site-specific GIC data for all sites with extra high voltage transformers interconnecting to the Bulk Power System, and to commit to periodic updating of observed GIC and time sequences for all relevant transformer locations. Moreover, the proposed standard does not require periodic update of assessments based on improved GMD data, updates to the GMD Benchmark Event, and reports of equipment impacts coincident or shortly after GMD events. Because the standards project for equipment monitoring was cancelled, the proposed standard should require improved GMD monitoring by means of additional GIC monitors—GIC monitors would be cost-effective as they cost only about $15,000 per monitor.
Individual
John Bee on behalf of Exelon and its affiliates
Exelon
Agree
No
Requirement R1: GIC models will require additional data beyond what is currently provided for power-flow models, etc. Examples include dc resistance for lines and transformers, substation grounding resistance and geographic coordinates, and variation of transformer reactive power loss with respect to GIC. This data is not readily available so consideration needs to be given to the time and effort that may be required to gather this information, and that some information e.g. transformer reactive losses due to GIC may not be known. Will the TO and GO be required to provide this data? Suggest that generic data be used in the event that the data is unavailable.
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. It is recommended 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 R7? 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.
No
Requirement 7: It appears that the analysis described for R7 will require that time-series GIC data corresponding to the benchmark event be simulated for each transformer subject to the requirements in the standard. Calculation of this data would essentially require the same models and study tools used by the PC and TP to meet the requirements described in R1 and R2, in addition to the ability to map these results into the corresponding time-series GIC for each transformer. Suggest that the PC or TP performing the studies described in R2 should be required to provide GIC data for each transformer sufficient for the TO or GO to perform the assessment described in R7. Requirement 7: In order to perform the assessments described in R7, accurate data is required for each transformer that describes thermal response with respect to GIC. Will manufacturers be required to provide this data? What if such data is not available, e.g., for older equipment installed in the field? The transformer manufacturers will be over whelmed which may result in a bottle neck. Is the expectation that each transformer that is in scope for the thermal assessment is analyzed individually? If the transformers are of the same design from the same manufacturer, it would be redundant to perform thermal assessment study on each transformer from that particular transformer manufacturer. It would be more practical to perform the study on just one type of the transformer from each manufacturer. Since 5-leg core and Shell form transformer designs are more susceptible to GIC, only transformers with these designs should be considered for system impact study. This study would provide worst case scenario for system impact. Suggest that similar transformer types and designs be analyzed as a group, i.e. one assessment be performed for all transformers of simular design and or type. Requirement 7: Our initial understanding was that assessment of thermal impact for all solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher was only required for transformers that were identified as having high GIC during the PC/TP GMD planning assessment. If this was the intent suggest rewording R7 to state: Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and

jointly owned power transformers with high-side, wye- grounded windings connected at 200 kV or higher that were identified as having high GIC in the GMD Vulnerability Assessment. Requirement 7: The thermal analysis described in the white-paper is somewhat detailed, requiring the ability to simulate and evaluate the thermal transformer response as a function of time, or analysis of the time-series GIC for each transformer to identify representative GIC "pulses" that can compared against manufacturer-provided capability curves. Suggest that the PC or TP define a more straightforward assessment methodology based on their simulation results; for example, possibly a single worst-case GIC pulse can be provided for each transformer to be screened. Requirement 7.3: The requirement reads "Describe suggested actions and supporting analysis to mitigate the impact of electromagnetically-induced currents, if any". We are not sure how the TO or GO can achieve this since it would require the PC to re run the GMD Vulnerability Assessment. Is the intent that this will be an iterative process? Requirement R6: The Rational reads "Distribution of GMD Vulnerability Assessment results and Corrective Action Plans provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies and planned mitigation measures may affect neighboring systems and should be taken into account by planners. Additionally, this GIC information is essential for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment". How would a TO or GO know what the impact of mitigation efforts performed by other entities will be on our own systems? The result could be constantly changing GIC profiles which would result in re-performing studies. Requirement 7: The "Transformer Thermal Impact Assessment" white paper (Pg. 2) states that a transformer GMD impact assessment must consider the transformer condition (e.g. age, gas content, and moisture in oil). Transformer condition is inherently subjective and dynamic. For these reasons, this parameter should be considered out of scope of the impact assessment. Requirement 7: The "Transformer Thermal Impact Assessment" white paper (Pg. 3) states that in order to determine maximum hot spot temperature rise due to GIC contribution "maximum ambient and loading temperature should be used". The base case condition should be more clearly defined. If short time emergency loading (i.e. loading beyond nameplate to the maximum temperatures permitted in IEEE C57.91) is used as the base case, the additional thermal rise due to GIC will exaggerate the actual effects of GIC to the transformer during normal operation. Note that the transformer manufacturer capability curves provided in the paper only define the GIC capability as a function of % MVA Rating without defining the what it actual is (nameplate versus capability). Suggest that normal continuous rating be used for the Thermal Impact Assessment.
Individual
Paul Rocha
CenterPoint Energy
CenterPoint Energy agrees in general that the standard drafting team has correctly identified the registered entities to perform the functions required in the draft standard. However,

CenterPoint Energy is concerned that, as currently written, the draft standard will create confusion among Planning Coordinators, Transmission Planners, Generation Owners, Transmission Owners and Regional Entities. R5 indicates that Planning Coordinators, in conjunction with Transmission Planners, will determine and identify individual and joint responsibilities for performing the required studies. However, the other requirements for performing such studies apply to all the applicable Transmission Planners and the Planning Coordinator for a region, which seems to be inconsistent with R5. CenterPoint Energy recognizes that R5 mirrors the language of TPL-001-4 R7, but an important distinction for this standard is the required communication between planning entities and owners in R6 and R8. The applicability of R6 and R8 to each planning entity results in duplicative communications. Another aspect of this standard is that due to boundary modeling considerations and emerging nature of these new requirements, it is likely that some regions would find it beneficial to consolidate modeling and analysis efforts, possibly into a single regional GMD Vulnerability Assessment. In such circumstances, the applicability to both the Planning Coordinator and each Transmission Planner would be problematic. CenterPoint Energy suggests that the SDT modify R1, R2, R3, R4, and R6 to read, “Consistent with the determination and identification of responsibilities in R5, the applicable Transmission Planner or Planning Coordinator shall…”. R8 would likewise be modified such the each owner is required to provide its assessment to the applicable planning entity, as determined in R5. If the SDT agrees with this change, we further recommend that R5 be renumbered as R1 since determination of applicability is a threshold function preceding the other planning functions. CenterPoint Energy also recommends that R5 be re-written to apply to both the Planning Coordinator and Transmission Planner, as follows: “Each Planning Coordinator and each of its Transmission Planners shall mutually determine and identify the individual and joint responsibilities…”.
Yes
CenterPoint Energy agrees that the proposed requirements meet the directives in Order No. 779 and are generally supported by the technical guides referenced in the standard. However, CenterPoint Energy recommends changes to some of the draft requirements, and CenterPoint Energy believes its recommended changes would also comply with the directives of Order No. 779 and would also be technically justified. In addition to the recommended changes discussed in the previous comment, CenterPoint Energy recommends the following additional changes to draft requirements: • Modify R1 to clarify that models should be developed for wye-grounded transformers with high side connections greater than 200 kV. • Add “if necessary to meet the performance requirements of Table 1”to the language in M3 to align M3 with R3. • Delete footnote 4 in Table 1. • Modify R7 to specify that an assessment of thermal impact should be conducted for power transformers that are potentially subject to peak GIC values above a certain threshold. CenterPoint Energy further proposes that the SDT set that threshold in the range of 50 to 100 amperes per phase. • Modify R6 and R8 to be consistent with our proposed changes to R7 and as discussed in the previous comment. These proposed changes are briefly explained below: • Applicable planning entities as defined in 4.1.1 and 4.1.2 of the Applicability section will typically have some transformers with high side connections below 200 kV or that do not have wye-grounded high side connections

within their system. CenterPoint Energy believes the SDT’s intent in R1 is that models should only be developed for the wye-grounded transformers connected at 200 kV or higher. To clarify this intent, CenterPoint Energy recommends that R1 be revised to read that each planning entity…”shall maintain ac System models and geomagnetically-induced current (GIC) System models of the wye-grounded transformers with high side connections greater than 200 kV within its respective area…”. • R3 indicates that each applicable entity “that determines..that its System does not meet the performance requirements of Table 1” is required to develop a Corrective Action Plan. However, M3 indicates that each applicable entity shall have evidence of a Corrective Action Plan, the implication being that this requirement applies regardless of whether a Corrective Action Plan is necessary to meet the performance requirements of Table 1. To align M3 with R3, CenterPoint Energy proposes that M3 be revised to indicate applicable entities “shall have evidence such as electronic or hard copies of its Corrective Action Plan if necessary to meet the performance requirements of Table 1…” • The expected occurrence of a P8 event is much less than other events defined in Table 1, such as P6 or P7. For more probable events, such as P6 and P7, Non-Consequential Load Loss can be relied upon as the primary means of compliance. Stated otherwise, footnote 4 is applied to P8, but it is not applied to more probable P6 and P7 events. CenterPoint Energy believes that if load shedding is an appropriate way to address more probable events such as P6 and P7, it is also an appropriate way to address a far less likely P8 event. Accordingly, footnote 4 should be deleted. • Regarding R7, CenterPoint Energy is concerned about the requirement to “conduct an assessment of thermal impact for all of its solely and jointly owned power transformers…” CenterPoint Energy believes the SDT and an overwhelming majority of experts would agree that an analysis using GIC capability curves, thermal response simulation, or “other technically justified means” is not necessary or beneficial for power transformers that have a peak GIC below a certain threshold value. CenterPoint Energy is further concerned about the lack of availability of GIC capability curves for most transformers and the lack of commercially available thermal response tools and modeling experts for a new type of analysis that most Transmission and Generator Owners do not perform today. The concept of a conservatively low “pass” or “fail” threshold is discussed in the Transformer Thermal Impact Assessment White Paper. The SDT may believe that peak GIC falling below a specified threshold should be considered a valid “technically justified means” of assessing a power transformer but, if so, an auditor could reasonably read the language in the draft requirement in a different way than the SDT intends. Accordingly, CenterPoint Energy proposes that the SDT modify R7 to specify that power transformers with peak GIC above a certain threshold must be assessed. CenterPoint Energy further proposes that the SDT establish that threshold between 50 to 100 amperes per phase or some other value that the SDT determines in its reasoned judgment. CenterPoint Energy believes that a threshold of 50-100 amperes per phase of peak GIC would be a conservatively low threshold above which detailed thermal impact assessments should be performed by the applicable asset owner. CenterPoint Energy proposes that the SDT establish the threshold for R7, rather than leaving the threshold to the discretion of individual entities, to ensure consistent implementation and to avoid skepticism of the GIC threshold value for entities that have low peak GIC values due to geography, geology, or other reasons. An alternative would be to set a

threshold value in the range of 50 to 100 amperes as the default, with an option to allow entities to use a value outside of that range that the planning entity technically justifies. • Regarding R6 and R8, CenterPoint Energy is concerned that the process coded in this draft version of the standard is impractical and unnecessarily cumbersome. In a region with 400-500 applicable transformers, for example, it is unnecessary and administratively burdensome to transmit GMD Vulnerability Assessments to the owners of all 400-500 transformers, regardless of GIC impact to each individual transformer. Additionally, as currently written, each owner would get at least two transmittals, one from the Planning Coordinator and one from a Transmission Planner, creating at least 800-1000 unnecessary notifications. A further complication is that each transformer owner could receive conflicting GMD Vulnerability Assessments from different planning entities. Under the R8 process, an additional 800-1,000 notifications would be provided by all the owners to the applicable Transmission Planner and Planning Coordinator. Furthermore, in a region with 10 highly interconnected planning areas, at least 100 transmittals of GMD Vulnerability Assessments would be required by Transmission Planners (10 sets of 9 transmittals to adjacent Transmission Planners and one transmittal to the Planning Coordinator). Applying CenterPoint Energy's previously discussed changes would address these concerns and make the implementation of standard more efficient. For example, under the R5 process, the planning entities might decide to perform a single region-wide GMD Vulnerability Assessment or, alternatively, create a planning coordination process modeled after the EOP-010 operational coordination process.
Yes
CenterPoint Energy commends the SDT for its work on this subject. In particular, the adjustments for latitude and soil conductivity result in a design basis event that can be applied throughout North America without the need for regional exceptions.
Yes
CenterPoint Energy generally agrees with the Implementation Plan developed by the SDT. One change that the SDT might consider is adding one year to the Implementation Plan for the parties to negotiate and determine responsibilities envisioned by R5, which CenterPoint Energy recommends be renumbered as a threshold R1 action. CenterPoint Energy's experience with similar processes, such as Coordinated Functional Registration to determine responsibility for Transmission Operator functions among multiple registered entities, causes CenterPoint Energy to believe that it will take time for multiple parties to reasonably vet and resolve this matter.
Individual
David Thorne
Pepco Holdings Inc
PC and TP seem redundent. Only need TP
Yes
Yes

Yes
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Do not agree. ATC supports the following comments submitted by the MRO NSRF: a. Revision to the Purpose b. Consideration of the sequence of assessments (TP/PC powerflow, then TO/GO thermal impact, then TP/PC complete assessment).
No
ATC supports the following comments as submitted by other organizations: • EEI REAC comment on inclusion “load loss” with a slight modification: Load loss for P8 should include both indirect Consequential (due to any cascading) load loss and Non-Consequential load loss. • ATC supports the MRO NSRF comments as listed below: (brief summaries only) (1) Double jeopardy with ac system model maintenance in R1 (2) Any other facilities in R3.1, (3) Other components of CAPSs in R3.2, perform R1 through R4 in R5, (4) Permission to receive assessments in R6, and (5) Have a current valid assessment in R7. Finally, ATC agrees with the MRO NSRF comment that the term, “susceptible”, in Note 3 of Table 1 needs clarification. An appropriate qualifier, or qualifiers, should be added such as “to tripping”, “to thermal damage, or “to failure”.
Yes
However, ATC believes the industry should keep trying to develop better Geoelectric Field Scaling Factors boundaries and scaling factor values.
No
ATC supports EEI REAC and MRO NSRF comments regarding factors such as the immaturity of space weather and geomagnetic sciences; the challenges of acquiring some data; and the improper sequence of analyses issue which suggest that the proposed time frame and sequencing may be unrealistic.

Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Ingleside Cogeneration LP (“ICLP”) believes that it is premature to include planners and operators who control low-risk assets. As captured in the baseline GMD event white paper, there are two key factors which clearly capture those transformers and transmission systems most prone to GIC – those at higher latitudes and those grounded in high-resistive earth. A bright line could easily be drawn that would capture locales that historically have been proven to be the most threatened. Those entities have a clear and immediate self-interest in protecting their investments in equipment and systems – whereas Generator Owners located in the southern U.S. do not. After sufficient experience with GIC modeling and validation has been achieved, it may be cost effective to pursue some expansion in scope. For now, we only see an increase in compliance overhead with no commiserate reliability benefit.
No
ICLP believes that the GMD event baseline is an excellent first step approximation of geomagnectically induced currents. However, there is nothing in the standard, guidance, or white papers that indicate that the baseline will be modified over time as the industry gains experience with the phenomena. The standard may not be the appropriate place for a continual improvement process, but we would like to see NERC commit to this action. Secondly, we were unable to find a correlation between the GO/TO’s assessment of transformer vulnerability and the PC/TP’s assessment of system performance. In the generator validation standards, the link was clear – planners and owners would work together to eliminate discrepancies. ICLP is concerned that unresolved conflicts may result in a violation of TPL-007-1 – either for the planner, the equipment owner, or both.
Yes
ICLP agrees that the underlying basis of the benchmark GMD event is as technically sound as it can be at this time. We would expect that corrections to the algorithm will be made as the industry gains experience with the phenomena.
No
ICLP believes that mandatory language needs to be added in TPL-007-1 that captures the reality that real-life response to GIC will not likely reflect simulated outcomes for quite some time. We are concerned that an auditor will assess a violation for a GMD event that leads to system instability or transformer damage without clear instruction to do otherwise. Only when the correlation between models and actual performance is confirmed, can this level of expectation be accommodated. This could take years or even decades – corresponding to the incidents of such rare Disturbances.
Individual
Erika Doot
Bureau of Reclamation

The Bureau of Reclamation (Reclamation) requests that the drafting team clarify why Reliability Coordinators are not included within the scope of the standard. In the Western Interconnection, the inclusion of the Reliability Coordinator would ensure an interconnection-wide perspective on transmission planning for geomagnetic disturbance events.
No
Reclamation does not believe that the standard clearly addresses FERC's directive to consider tasking Planning Coordinators or another functional entity "to coordinate assessments across Regions… to ensure consistency and regional effectiveness." Order No. 779, ¶ 67. Reclamation does not believe that providing copies of GMD Vulnerability Assessments and Corrective Action Plans to adjacent Planning Coordinators and Transmission Planners as required by R6 amounts to coordinating assessments to ensure consistency. Reclamation suggests that the drafting team add an additional requirement to the standard to more specifically address coordination of GMD assessments among regions.
Yes
Reclamation believes that the proposed benchmark GMD event is technically justified because it is based on the best available data, and because the Quebec event provided generally conservative thermal analysis results for power transformers. Reclamation believes that based on the characteristics described in the whitepaper, Planning Coordinators and Transmission Planners will incorporate additional location-specific information to ensure that assessments are robust.
No
Reclamation suggests that the Implementation Plan for R7 be updated to allow a phased approach to compliance because entities may not be able to complete thermal impact assessments for all transformers with high-side, wye-grounded windings connected at 200kv or higher within one year of receiving geomagnetically-induced current flow models from the Planning Coordinator and Transmission Planner. For example, an entity with over 200 qualifying transformers may not be able to complete thorough studies in a compressed one-year timeframe. Reclamation suggests a phased implementation period of 30% of applicable devices assessed within 36 months of regulatory approval, 60% of devices within 48 months, and 100% of devices within 60 months. This phased implementation schedule would allow Transmission Planners and Planning Coordinators to receive all thermal impact analyses with adequate time for review before the next 60-month GMD Assessment required by R2. Reclamation has additional comments on the proposed requirements that are not covered in the questions posed by the drafting team: Reclamation suggests that R7 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 suggests that R2 should include an additional subrequirement requiring the Planning Coordinator and Transmission Planner to consider the results of thermal analysis received from Transmission Owners and Generator Owners when performing subsequent GMD Assessments. If the drafting team declines to incorporate this additional subrequirement, it should eliminate R8 as a purely administrative requirement or modify R8 to require Transmission Owners and Generator Owners to provide study results within 90

days of a request by the Planning Coordinator or Transmission Planner. Reclamation suggests that the drafting team update R5 to include the clarifying language from M5 that Planning Coordinators and Transmission Planners should demonstrate agreement has been reached with entities responsible for performing studies required for the GMD Vulnerability Assessment. Finally, Reclamation requests that the drafting team include an additional requirement requiring Planning Coordinators and Transmission Planners to demonstrate that agreement has been reached regarding proposed actions in a Corrective Action Plan that are anticipated to be completed by Transmission Owners or Generator Owners.
Individual
Venona Greaff
Occidental Chemical Corporation
Agree
Ingleside Cogeneration, LP.
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
The proposed benchmark GMD event appears to be supported with reasonable technical arguments. However, we would appreciate clarity on the following points: • Why is a design basis of 1 in 100 years appropriate for a planning standard. 1 in 50 years would be closer to extreme events such as ice storms. • Why was 8 V/km selected as the reference V/km magnitude when extreme value analysis suggests that the high end should be 5.8 V/km? • Is there a geomagnetic latitude below which there is no point in carrying out detailed studies?
Yes
It is not clear why the first GMD event is labelled P8 instead of P1. This should be clarified or changed. In R3, if the Planning Coordinator and the Transmission Planner are separate entities, then they should reach agreement on the Corrective Action Plan, as well as reaching agreement on the criteria identified in R4. The skill set needed to carry out the required studies is not widely available in the industry. The proposed standard indicates in various places that certain flexibility is permitted if technical justification is provided. Who will be qualified to assess if a given technical justification is reasonable. NERC, the Planning Coordinator? In Requirement 7.3, the TO is asked to suggest mitigation plans while R3 asks TC/TP to have a Corrective Action Plan. It should be clarified that this will be an iterative process to avoid redundancy or confusion. If the TO or GO identifies a needed change as a result of the studies from the TP (e.g. a transformer must be taken out of service) then this will have an impact on the studies that will be done by the TP and which in turn will affect subsequent thermal impact studies. MOD-032, which is replacing the old MOD, should now

include the data/models required for TPL-007 studies in MOD-032 Attachment 1. These data and models are not mentioned in MOD-032 Attachment 1. Until then TPL-007 should clarify what data/model should be provided by TO.
Individual
David Jendras
Ameren
No
Is it intended that there be any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? We ask for clarification on other contingencies besides adjusting the models to reflect posturing in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. On Page 8, Table 1, Steady State A: We request the SDT remove possible dynamic modeling/simulation implications by considering the following change: • Current Language for Steady State A: The System shall remain stable. Cascading and uncontrolled islanding shall not occur. • Proposed Language for Steady State A: Cascading and uncontrolled islanding shall not occur. On Page 8, Table 1, Steady State Performance Footnotes #4: We request the SDT remove possible dynamic implications by considering the following change: • Current Language Footnote #4: The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. • Proposed Language Footnote #4: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In

addition to constructing the necessary models of one’s own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. We request that the entity be able to use either calculated Rgnd (equivalent resistance from the substation ground grid to remote earth), or measured Rgnd. Both NERC Application Guides imply that Rgnd should include the effects of before transmission shield wires and/or multi-grounded neutrals being connected Some existing Rgnd values may've been measured before transmission shield wires or multi-grounded neutrals were connected, or prior to a substation addition. Rather than require potentially burdensome measurement, allow the entity to make a calculated adjustment, if appropriate.
Individual
Eric Bakie
Idaho Power Company
Yes
Yes
Idaho Power System Planning agrees that the requirements in TPL-007 address the directives of FERC Order 779.
Yes
Idaho Power System Planning agrees that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments.
No
Idaho Power System Planning feels that the proposed time frame and sequencing proposed in the Implementation Plan is unrealistic; GMD modeling data is not as commonly available as other data types reported in current MOD Standards; thus additional time will be required for entities to compile the required GMD modeling data. IPCO System Planning feels that a realistic effective dates for R1 and R5 is 24 months and 36 months for R2, R4, and R6. The proposed timeframes for R7 and R8 are unrealistic; IPCO System Planning feels that the transformer assessments should be implemented in a phased percentage of the entity's applicable equipment over a 5 year period (20% per year starting with most vulerable transformers in the first 20% block; similar to the approach used in MOD-026/MOD-027). Idaho Power System Planning feels that a realistic effective date for R3 is 60 months. Idaho Power- Power Production Engineering believes the implementation plan is too aggressive. More time for phase-in should be allowed.
Group
Arizona Public Service Company
Janet Smith

NO - 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.
Yes
No
AZPS requests that the benchmark GMD event be comparable to a known event, such as the 1989 event in Quebec, to ensure that the benchmark appropriately simulates actual events.
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.
Individual
Thomas Foltz
American Electric Power
Yes
The proposed requirements are precluding the engineering which should drive them. More studies are needed before best practices can be determined. For example, are the potential system impacts and utility of available mitigation options well understood? A neutral blocking device on an autotransformer may not provide the level of mitigation expected. This is due to the fact that an autotransformer has two paths for GIC flow – through the series winding connecting primary and secondary terminals and through the common winding connecting secondary and neutral terminals. Blocking the neutral only eliminates that portion of GIC flowing in the common winding. The GIC still flows through the series winding (albeit at a possibly reduced level) which still leads to half-cycle saturation and increased reactive power losses. The magnitude of these losses may possibly be reduced by blocking devices but not eliminated. How are the system and transformer models verified, and what confidence is there that what these models are providing is accurate? AEP disagrees with requiring thermal studies for all GO/TO transformers. Rather, the PC/TP should complete their GMD vulnerability assessment and identify where the risks are. GO/TO should be required to study only those transformers in the designated high risk areas based on the vulnerability study results.

Yes
Using statistical methods to derive the parameters of an essentially random process is completely justified. Also, ignoring very localized events in the derivation process is also justified on the basis that the system we are analyzing, and the effects we are studying, are spatially very widespread.
No
While the implementation plan is adequate for the system vulnerability assessments, it would not be adequate for the transformer thermal assessments, specifically for existing transformers for which the pertinent design and performance data needed for the assessments is not available. While AEP will make every attempt to obtain the data necessary for these assessments, some vendors have inferred that not all transformers will have readily available models (nor ways of generating them) from which to derive the required data from simulation. Further consideration will be required to determine the number of transformers where obtaining design and performance data proves problematic, and determine methods to address any unavailable data. Conducting physical testing of these units as an alternate means to derive the required data, is extremely problematic if not entirely impractical. The nature of this testing precludes any type of field test, as monitoring internal hot spot temperatures requires the transformer be retrofitted with thermal sensors. This retrofit can only be accomplished at a transformer manufacturing facility, as it requires the untanking of the unit. Therefore, any physical test would require taking the unit out service, prepping and then shipping the unit to a transformer manufacturing or test facility, retrofitting the unit with thermal sensors, conducting the tests, shipping the unit back to the substation, and finally, prepping and putting the unit back in service. Even if this process could be accomplished, most facilities are not able to conduct the required tests as the electrical sources needed are not strong enough to supply the required reactive power. In the event thermal models are not available, and physical testing is not feasible, would there be a way to develop standard models for each transformer design type? Such models could then be scaled with available data to provide a reasonable estimate of thermal performance. If so, these models could be used to estimate the performance for those units in which detailed data is not available. The 36 month time frame for the transformer thermal assessments is not adequate given the level of work required to obtain the required data. Furthermore, transformer manufacturers, who will be instrumental in this process, may not be able to fulfill the high demand for this service in the required time due to very little demand diversity. AEP is also concerned with what recourses are available, if after every reasonable attempt to obtain the required data have been exhausted, the data is still not available. It is unclear how often the TO/GO must repeat their R7 required thermal assessments. Is it every time the PC/TP repeats their GMD Vulnerability Assessment? Every 5 years? Never? Since there is no benefit in repeating a study when nothing has changed, AEP recommends the standard be revised to only require the TO/GO to repeat their thermal assessment if the GIC value from the PC/TP differs more than X% for the value used in the most recent thermal assessment. It is unclear of the timing between installing a new/spare transformer and completing the thermal assessment. The standard should address the timing of the completion of the thermal assessment compared to the installation of a system spare. It should be acceptable

to complete the thermal assessment within a designated time frame (i.e. 12 months) after a spare/new transformer has been installed. Requiring the assessment be completed prior to placing a spare in service could delay returning equipment to service following a failure and result in decreased BES reliability. As proposed, the implementation plan may unintentionally shorten the TO/GO implementation period based upon the responsiveness of the PC/TP. Consider the following: If the PC/TP takes the entire 24 month period to complete their assessment (Per R2) and then takes the entire 90 days to distribute the results to the TO/GO (Per R6), the TO/GO will only have approximately 9 months to complete their thermal assessments because they spent the first 27 months waiting on data from someone else. The issue could be resolved by revising the implementation plan to require the TO/GO to be 100% compliant with R7 and R8 36 months after regulatory approval or 24 months after receiving the GMD Vulnerability Assessment from the PC/TP, whichever is longer.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Group
SPP Standards Review Group
Robert Rhodes
‘High side’ is not hyphenated in Applicability sections 4.1.1 thru 4.1.4. It is hyphenated in Requirement R7 and in the Comment Form. It is not hyphenated in the Implementation Plan. We suggest the drafting team be consistent in the handling of this term, whichever it chooses to use. Generation Owner in 4.1.4 should be Generator Owner.
No
FERC Order 779 requires assessments of Bulk-Power System transformers. The proposed standard establishes a threshold of 200 kV for the applicable transformers. Question 1 references the whitepaper associated with EOP-010-1 which provided the justification for the threshold in that standard. We concur with the 200 kV threshold but suggest that the drafting team make the linkage between that whitepaper and TPL-007-1 more clear, specifically referencing the previous whitepaper. Otherwise, it appears that the proposed standard falls short of the FERC Order. Requirement R3 requires the development of a Corrective Action Plan. Current TPL standards require Corrective Action Plans for N-1 and N-2 conditions but do not require them for N-3 and beyond. If impacts from a GMD event create N-3 or beyond conditions, this standard goes beyond existing practice to require Corrective Action Plans. Shouldn’t there be consistency within the standards in this area? Requirement R6 requires the responsible entities to provide GMD assessment results to any functional entity with a reliability related need within 30 days of the request. This requirement is too broad and open-ended. How does one determine what a valid reliability related need is? What qualifies that need as valid? Without additional clarification by the drafting team this could open

Pandora's box. Here are some additional typo/grammatical suggestions for the proposed standard. Replace 'New' with 'Newly' in Requirement R1, Part 1.3. In multiple places throughout the requirements and in the VSLs, terms such as 30-calendar days, 90-calendar days and 60-calendar months should be hyphenated as shown. Also, in those places where the reference to 'calendar' has not been included, it should be included. This applies to all posted documents. In Requirement R2, the term 'steady state' is not hyphenated. In other places throughout the documents, the term is hyphenated. We encourage the drafting team to be consistent with the correct format throughout the posted documents. We believe the use of subparts is currently on the out at NERC. As used most recently in CIP-014-1, we suggest removing subparts 2.1.1 and 2.1.2 and replace them with bullets. In that case in the two bullets under Part 2.1, capitalize 'Term' in '…Near-term Transmisssion Planning Horizon.' as it is a defined term in the NERC Glossary. Replace the 'by' in the 1st line of the Rationale Box for R4 with 'be'. In Measure M5 'e-mail' is hyphenated. In Measures M6 and M8 'email' is used. We again encourage the drafting team to be consistent with the correct format whichever it may be. Replace the reference to Requirement R5 at the end of Measure M6 with Requirement R6. Delete 'wye' in the 4th line of Measure M8. In Table 1, insert an 'a' between 'of' and 'P8' in item b. under Steady State. The following are in Attachment 1: In the 3rd line of the 2nd bullet on Page 10, replace 'geolectric' with 'geoelectric'. Insert a comma in the date at the top of Page 13; March 13-14, 1989. The following refer to the VSLs: Capitalize 'Parts' in the High and Severe VSLs for R3 and the Moderate and High VSLs for R7.
No
We believe the 2nd 'conductivity' in the 7th line of the last paragraph under the Statistical Considerations section on Page 9 should be deleted. In the 4th line of the 1st paragraph under the Extreme Value Analysis section on Page 12, 'geo-electric' is hyphenated. No where else in any of the documents is this term hyphenated. We suggest the drafting team be consistent with the use of this term throughout the documents. In the 1st paragraph under Table 1-1 on Page 13, replace'geolectric' in the 2nd line with 'geoelectric'. Insert a comma in the date in the last line of the paragraph under the Impact of Waveshape on Transformer Hot-spot Heating at the bottom of Page 16; March 13-14, 1989. Although this document mentions the difference between geographical and geomagnetic latitude, we suggest that the drafting team include support for the apparent 10 degree difference between the two quantities.
No
A 12 month implementation for Requirement R1 may be too short. This is for model development and it may take more than a year to research and establish the needed models. We suggest that the implementation for R1 be changed to 18 months and that it be coordinated with the MMWG effort. Since the assessments required in Requirement R2 cannot be conducted until the models have been developed, the implementation for R2 should also be extended by 6 months to 30 months and should be tied to the development of the models in R1. For consistency with the remaining requirements we suggest extending all the implementation periods by 6 months.
Individual

shirin.friedlander@ladwp.com
ladwp
Even though,LADWP's response is not addressing this specific question but we believe that the following comments are relevant to the applicability of the standard: LADWP would like to emphasize the regional differences based on geographical location due to the nature of GMD. Furthermore, LADWP believes that it is prudent to remove Registered Entities from the applicability of some requirements as long as they determine that GMD is of very low impact based on a simpler calculation (such as from the Geoelectric Field values) due to their geographical location. Attachment 1 of TPL-007-1 provides the means for calculating Geoelectric Fields for the Benchmark GMD Events. LADWP is proposing that the following language be added to the end of Sections 4.1.1 through 4.1.2 of the Applicability of TPL-007-1: “..and have determined that the Geoelectric Fields for the Benchmark GMD Events is more than XX[fill in the blank].”
Individual
Joshua Andersen
Salt River Project
SRP recommends the standard be applicable to the Reliability Coordinator(RC). SRP suggests that the RC determine which Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners shall create and maintain GMD models per a GMD Vulnerability Assessment or a specific geomagnetic field scaling factor value. This will decrease the administrative burden on entities that are minimally affected by GMD events.
Yes
Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst submits the following comments for consideration: Applicability Section – ReliabilityFirst believes the Applicability language needs to be a little clearer. The white paper on applicability seems to be correct in identifying transformers, but in shortening it, some clarifying information has been lost. ReliabilityFirst recommends the following as an example

for consideration: “Planning Coordinator with a Planning Coordinator area that includes a power transformer(s) or auto-transformer(s) with a wye-grounded or wye-impedance grounded high side connected at 200 kV or higher” Applicability Section - GIC can be altered with the use of series capacitors on longer transmission lines. Thus, shouldn't applicability be expanded to 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 in Requirement R5. Entities serving load within one or two buses of a wye-grounded transformer may need to be involved in the study also. Otherwise, the solution of shedding load by UVLS once every 100 years may be ignored.
ReliabilityFirst submits the following comments for consideration: Requirement R1 - Requirement R1 references “supplemented by other sources as needed, including items represented in the Corrective Action Plan”. This is the first place the term “Corrective Action Plan” is referenced and it is unclear as to what “Corrective Action Plan” it is referring. If it is referring to the “Corrective Action Plan” required in Requirement R3, ReliabilityFirst recommends adding a reference to Requirement R3 in Requirement R1 such as “…including items represented in the Corrective Action Plan developed in Requirement R2 – There should be a hyphen in between the term “Near” and “Term” to be consistent with the NERC Glossary of Terms definition. Requirement R2, Part 2.1.1. – 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”. Requirement R2 - There are Planning Coordinators and Transmission Planners in portions of the grid that have low susceptibility to GMD, due to being further south, and with low earth conductivity. The screening process outlined in: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf indicates that if voltage disturbance is less than 3% at capacitor banks, SVCs and transformers, with power flow quality data, then no further analysis needs to be required. Thus, Requirement R2 needs to be clarified. The GMD Vulnerability Assessment could consist of just the screening for 3% voltage disturbances and nothing more. Only if the 3% screening criteria is violated would it be necessary for the assessment to dig deeper into vulnerability of individual transformers, and search for violations of P-8. If the study shows no voltage disturbances over 3%, then the Planning Coordinator and Transmission Planner have no need for GMD voltage criteria (Requirement R4) or an impact analysis on each transformer (Requirement R7 and Requirement R8) Requirement R3, Part 3.1 – ReliabilityFirst recommends removing the “Examples of such actions include: “ language and modifying Part 3.1 as follows: “List System deficiencies and the associated actions needed to achieve required System performance such as, but not limited to:” Requirement R6 - ReliabilityFirst recommends clarifying the term “days” (i.e., is it calendar or business days?): “…a written request for the information within 30 [calendar] days of such a request. Requirement R8 – ReliabilityFirst recommends clarifying the term “days” (i.e., is it calendar or business days?): “…within 90 [calendar] days of completion…” Table 1 footnote 4 - In Table 1 footnote 4, ReliabilityFirst does not believe non-consequential load loss, or the curtailment of Firm Transmission Service should not be considered as the primary method of achieving required performance. This is a once in 100 year type event, and

UVLS could be the best choice for mitigation, and should not be discouraged by a TPL-007-1 standard. ReliabilityFirst recommends removing the following sentence from Table 1, note 4 "but should not be used as the primary method of achieving required performance".
Group
Dominion
Louis Slade
Our response is that we agree.
No
Dominion is concerned with the sequence of activities that need to be followed to comply with the requirements. We suggest that all requirements be broken down, restructured, and re-organized so that they align with the actual steps of the process and have no circular dependencies. Following are examples of our concerns; • Before the applicable entity can comply with R2 (perform GMD Vulnerability Assessment), the PC and TP must comply with R5 (decide upon who does what in performing the assessmentIf Dominon understands R4 correctly (have criteria for steady-state voltage limits), it seems like something that should be done prior to or as part of R2 (perform studies). R2 requires an assessment of the Near-Term Transmission Planning Horizon, but the Time Horizon for the requirement is Long-Term Planning. We suggest the SDT make a change so that there is consistency. • By definition, a GMD Vulnerability Assessment includes consideration of localized equipment damage. The PC and TP cannot consider potential damage without the TO and GO having completed R7 (assessment of thermal impact) and R8 (provide thermal impact assessment to PC and TP). Also, the PC and TP cannot perform R3 (develop Corrective Action Plan) prior to the TO and GO completing R7 and R8 if the Corrective Action Plan is supposed to address equipment damage. However, the TO and GO cannot do R7 and R8 without the PC and TP having done R6 (distribute GMD Vulnerability Assessment and Corrective Action Plan) since the GIC studies are a pre-requisite of the thermal impact assessment. The last part of R6 includes a requirement to provide assessment results to any entity with a reliability need within 30 days of receiving a request from such an entity. Dominion suggests deleting this requirement (pursuant to P81) since it is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES.
Yes
Dominion is concerned about the website links back to the 2013-03 Project page in Attachement 1 and the Application Guidelines, how is NERC going to ensure these links will remain valid after the standard is approved? Going forward, Dominion suggests that any reference materials be included in this and other standards as attachments or appendices due to the concern mentioned above.
Yes

Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes (no buttons were present in the electronic form)
No
[A] Alternating Current (AC) and Direct Current (DC) - On p. 3, Requirement R1 of the draft standard uses the phrase “maintain ac System models …” The Free Online Dictionary states that the abbreviation for alternating current is “AC” (capitalized) citing The American Heritage Dictionary. This definition makes no provision for the lower case abbreviation “ac.” alternating current, n. Abbr. AC An electric current that reverses direction in a circuit at regular intervals. The American Heritage® Dictionary of the English Language, Fourth Edition copyright ©2000 by Houghton Mifflin Company. Updated in 2009. Published by Houghton Mifflin Company. All rights reserved. See http://www.thefreedictionary.com/alternating+current Our recommendation is that the drafting team use the capitalized abbreviation “AC” in order to avoid any confusion with a potential typographical error “ac” of the two-letter word “as.” Since “AC” is not a NERC Glossary term nor is it defined in the draft standard, but is a term of art perhaps it should be spelled out and the abbreviation listed in parentheses, as with GMD and GIC. Further, it is our understanding that there are both AC and direct current (DC) components to Geomagnetically-Induced Currents (GIC’s). So, are AC models sufficient to capture the entire impact of a geomagnetic disturbance (GMD)? Assuming that both kinds of models are necessary, then Requirement R1 should read: R1. Each Planning Coordinator and Transmission Planner shall maintain [add: “alternating current (AC) and direct current (DC)”] [delete: “ac”] System models … In fact the Rationale Box on p. 4 supports this assertion where it states: “A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. … The ac System model is used in conducting steady-state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.” Further support for the need for both AC and DC modelling comes from the Geomagnetic Disturbance Planning Guide, December 2013, which on p. 7 states: dc network model. The dc network consists of circuit resistances, transformer winding resistances, and station grounding resistances (see [2]). In principle, the model is straightforward, and has a high level of confidence so long as transmission line and transformer resistances are known. … And on p. 9 which states: 3.2 System Model - The dc equivalent system model is thoroughly discussed in the NERC GIC Application Guide [2]. And on p. 10, which states: • The dc network model should be consistent in size and scope with the ac model … • Equivalent circuits in the ac model are generally not directly translatable into dc equivalents. Guidance on dc network equivalent circuits is provided in the NERC GIC Application Guide. [B] Delete Requirement 2.1.2 on p. 4 Requirement R2. Peak-load conditions are all that matters. [C] Table 1 Footnotes Table 1, p. 8: Footnote 1 – The footnote simply repeats the initial condition statement, but could be expanded to provide examples.

No
GMD’s cover large regions, so it’s very important to have modelling data from neighboring regions, especially in the congested Northeast, in order to identify impacts from external equipment. How does the drafting team envision ensuring that actions taken in one area do not negatively impact entities in adjacent areas, e.g., PJM CAP negatively affecting NYISO entities. For example, a PJM CAP might result in GIC’s flowing on adjacent NYISO elements exacerbating the problem in NY. What recourse would an adjacent region have to prevent such actions from negatively impacting and shifting GMD-related costs to their region?
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC Planning Standards Subcommittee
Individual
Andrew Gallo
City of Austin dba Austin Energy
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question. Additionally, AE requests the Standard Drafting Team (SDT) provide an additional 12 months in the Implementation Plan for Requirement R1, for a total implementation time period of 24 months. As such and in combination with CenterPoint Energy’s recommendation to add one year for R5, AE recommends the SDT revise the Implementation Plan to read “Requirements R1 and R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority....” This additional time would allow entities to procure the necessary software and gather the unique inputs to the model required in R1 as well as fulfill the necessary coordination under R5. AE notes R2, R4 and R6 will be due within the same time frame (2 years), but AE believes that timeframe is still feasible.
Individual

George H. Baker
James Madison University
Agree
Foundation for Resilient Societies
Individual
Dianne Gordon
Puget Sound Energy
The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC's respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC's to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis.
No
While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Group
Duke Energy
Michael Lowman

Duke Energy would like to commened the SDT on the work they have done on this project and agree that the appropriate Functional Entities in the Applicablity Section of this standard were identified.
Yes
(1) Duke Energy suggests adding the flowing wording to R6 of this standard: “Each Planning Coordinator or Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan(s), if any, to adjacent Planning Coordinators, adjacent Transmission Planners, Transmission Owners ,Generator Owners, and Reliabity Coordinator in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any other functional entity that demonstrates a reliability related need and submits a written request for the information within 30 days of such a request.” Since the RC is the responsible entity for developing, maintaining and implementing a GMD Operating Plan, we believe the RC should also be provided and made aware of the GMD Vulnerability Assesment(s) and Corrective Action Plan(s) in their respective RC area. We also believe that the decision on who will distribute the plan(s)/assessment(s) should have been identified in R5. By replacing “PC and TP” with “PC or TP”, this will remove the uncessary distiribution of the GMD Vulnerability Assesment and CAP to the same entitiy on multiple occasions and also clearly identify who is responsible for providing those assessments and plans. (2)Duke Energy suggest rewording M5 as follows: “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that an agreement has been reached on individual and joint responsibilities for performing and distributing the required studies for the GMD Vulnerability Assessment in accordance with Requirement R5.” We believe this modification would add clarity on who is responsible for not only perfoming, but also distributing the required studies for the GMD vulnerability assesments.
Yes
Duke Energy agrees that the benchmark GMD is technically justified and addresses FERC order 779.
Yes
Duke Energy agrees with the a multi-phased approach to the Implementation Plan.
Individual
Angela P Gaines
Portland General Electric Compay
The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC’s respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC’s to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be

shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis
No
While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Individual
Robert Coughlin
ISO New England Inc.
The organization of requirements is confusing. The SDT should reorganize the order in which the requirements are listed to group together requirements that cover a similar activity and that have the same “go live” dates under the implementation plan and to organize these groups in a sequence that follows a logical workflow. As illustrated below, organizing the requirements so that they read chronologically (according to Implementation Plan) makes it easier to understand. In addition, or alternatively, the SDT should include explicit language in the Requirements explaining the linkages amongst requirements. For example, until one reads the Implementation Plan, it is not obvious that information gathered pursuant to R7/R8 is meant to be an input to the work required under R3. Even though this can be understood after reading the Implementation Plan, the Standard requirements should explicitly link to each other, as applicable. Another example is R2/R5. While R2 requires completion of a GMD

Vulnerability Assessment, R5 separately requires PCs, along with each TP, to determine and identify individual and joint responsibilities for performing required studies for the GMD Vulnerability Assessment. A third example is that, although the Corrective Action Plan is referenced in in R1 and M1, it is not described in R1. Rather, it is described in R3. We suggest revising the reference in R1 to "the Corrective Action Plan developed under R3." In short, these requirements should not be divorced from each other. Listing the requirements chronologically as we propose below should help alleviate most of these issues. Requirements listed "Chronologically" Effective on the first day of the first calendar quarter that is 12 months after FERC approves: R1. Each Planning Coordinator and Transmission Planner shall maintain AC System models and geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. R5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD Vulnerability Assessment. Effective on the first day of the first calendar quarter that is 24 months after FERC approves R4. Each Planning Coordinator and Transmission Planner shall have criteria for acceptable System steady state voltage limits for its System during the GMD conditions described in Attachment 1 R2. Each Planning Coordinator and Transmission Planner shall complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis. R6. Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. Effective on the first day of the first calendar quarter that is 36 months after FERC approves R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. Effective on the first day of the first calendar quarter that is 48 months after FERC approves R3. Each Planning Coordinator and Transmission Planner that determines through the GMD Vulnerability Assessment conducted in Requirement R2 that its System does not meet the performance requirements of Table 1 shall develop a Corrective

Action Plan addressing how the performance requirements will be met. Also, please note the following: R6 and M6: - R6 requires distribution of the GMD Vulnerability Assessment to certain entities regardless of whether it is appropriate to do so. We recommend that distribution of the GMD Vulnerability Assessment be clarified and limited with wording such as "…each Planning Coordinator and Transmission Planner shall provide its GMD Vulnerability Assessment upon the request of a relevant Transmission Owner or Generator Owner in its respective planning area or of an adjacent Planning Coordinator or Transmission Planner." - M6 should include reference to distribution of results to relevant Transmission Owners, Generator Owners or adjacent Planning Coordinators or Transmission Planners that have requested the GMD Vulnerability Assessment. R7 – This requirement should refer to the GMD Vulnerability Assessment that was distributed to Transmission Owners and Transmission Operators as specified in R6.
Group
Bonneville Power Administration
Andrea Jessup
Yes.
Yes
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. Approximations may be useful in ruling out concern if the transformer sees little impact from Geomagnetically-Induced Current (GIC), even with approximate characteristics' modeling, but may leave doubt as to how impacted the transformer would be under significant GIC flow. The transformer behavior modeling still needs significant advances to be considered completely reliable. BPA also suggests consolidating language referring to Corrective Action Plans in either R1 or R3, to eliminate the possibility of violating both R1 and R3 for the same reason. Likewise, footnote 4 in Table 1 should not instruct on the content of the GMD Operating Procedures required by EOP-010-1. If this language is necessary, it should be incorporated in a future revision to the relevant reliability standard.
Yes
BPA believes that the overall concepts appear technically sound, but industry study tools are not yet configured to input the benchmark event, along with geomagnetic latitude and geographic earth resistivity parameters. Additionally, it is unknown whether the application of the benchmark model will produce results with the consistency and accuracy needed for operating decisions, and electrical system modifications to significantly mitigate GIC impact. This will require actual use and experience with the benchmark model. It should, however, inform on whether a network change significantly improves or worsens the situation.
Yes
Individual

Patrick Farrell
Southern California Edison Company
Yes. SCE agrees with the selection of functional entities by the drafting team.
Yes
Yes
Yes
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes, we agree.
No
The SDT respectfully requests the SDT to consider removing the term(s) “posture or posturing” and use language such as “changes to system configuration or configuration” to add further clarification in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. Two examples of this requested change follow: Rationale for R1. Current language: The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. Language for Consideration: The projected System condition for GMD planning may include adjustments to system configuration to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. A second example can be found on page 8, Table 1, Initial Condition: Current Language: 1. System as may be postured in response to space weather information, and then Language for Consideration: 1. System as may be configured in response to space weather information, and then Further, it is requested to have SDT clarify whether it is the SDT intention that there are any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? On page 8, Table 1, Steady State A: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Steady State A language: The System shall remain stable. Cascading and uncontrolled islanding shall not occur. Language for Consideration: Cascading and uncontrolled islanding shall not occur. On page 8, Table 1, Steady State Performance Footnotes #4: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Footnote #4 language: The objective of the GMD Vulnerability Assessment is to prevent instability,

uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Language for Consideration: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
The SDT is requested to consider modification of the Implementation Plan for TPL-007-1 – Transmission System Planned Performance during Geomagnetic Disturbances, Effective Dates. Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In addition to constructing the necessary models of one's own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. In addition, there is concern that it will take considerable time to calculate values of Rgnd, based on location dependent earth resistivity and ground mat design at each substation. If actual measurements of Rgnd are required, we can only practically measure Rgnd at in-service substations with all neutral connections and static wires in place. Are calculated values of Rgnd sufficient? The comments expressed herein represent a consensus of the views of the above named members of the PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Gul Khan
Oncor Electric Delivery Company LLC
Oncor believes that the functional entities identified in the standard have been correctly identified. R5 states "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD

Vulnerability Assessment." It would be more feasible to perform this function prior to R2 which is when the GMD assessment is completed. Using that rationale having R4/M4 along with R5/M5 prior to R1/M1, and R2/M2 would allow for proper preparation before the completion of the assessment.
Yes
Oncor agrees that the technical guidance for the Vulnerability Assessments meet the directives of Order 779
Yes
Oncor strongly supports the proposed benchmark GMD event believing it to be technically sound reflecting good engineering practices as typically employed by electric utilities. All of these requirements have been fully addressed in a manner that we believe to be reasonable and defensible based on the current state and understanding of severe space weather and its impact on the BPS. The SDT based their Benchmark event on a 1 in 100 year event, which exceeds normal utility practices by a factor of 2 for earth based weather related catastrophic event analysis. Oncor sees great benefit in the calculation of the regional geoelectric field peak amplitude using a scaling factor to account for local geomagnetic latitude, and a scaling factor to account for the local earth conductivity structure.
Yes
Oncor supports the proposed Implementation Plan believing that it provides sufficient time for entities to effectively assess and develop Corrective Action Plans. The timeframe may appear long to outside observers but is short for the first time application by many different entities in the process.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
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. Comments: It is well-recognized in the industry that single-phase transformers, are generally used on 500 kV-and-up generator step-up transformers (GSUs),which are much more susceptible to geomagnetic disturbances (GMDs) than are the three-phase GSUs used at lower voltages. Susceptibility also varies with latitude, as described in NERC's GMD publications. Before making the standard applicable at the 200 kV threshold, it would be appropriate for the SDT to perform a screening study to determine the transformer types and locations for which GMD-related analyses are justified, rather than imposing obligations relating to facilities where there may be little or no benefits.
No

NERC’s Transformer Thermal Impact Assessment White Paper states on p.9 that GOs and TOs are to analyze the impact of GMDs on applicable transformers based on manufacturer capability curves or via calculating thermal response as a function of time. We (and probably almost all entities) have no manufacturer capability curves for geomagnetically-induced current (GIC) It is not reasonable to expect that such information will become available for equipment that was designed and manufactured in most cases decades ago. Calculating thermal response as a function of time is consequently the only methodology available, and the Transformer Thermal Impact Assessment White Paper states on p.9 that one can then use measurements (i.e. the results of owner-conducted tests), manufacturer’s calculations or generic published values. No guidance is given on how to conduct GIC testing on transformers, nor is it conceivable that GOs and TOs could perform such experiments on in-service equipment, and manufacturer calculations are once again not available. This situation leaves GOs and TOs dependent on generic GIC capability curves, which NERC’s Geomagnetic Disturbance Planning Guide says on p.12, are available in reference #3, the NERC Transformer Modeling Guide. This document is shown as being “forthcoming” however, and we have been unable to obtain other sources of generic data. Thus, the tools required to fulfill requirement 7 of TPL-007-1 do not presently exist. The Transformer Modeling Guide should set forth a step-by-step calculation methodology taking one from the GIC flow inputs of TPL-007-1 requirement 7.1 to a final-product thermal response trend, using NERC-published generic thermal response curves that cover all transformer types, sizes and situations. We will comment on this document once it is published, but until then we cannot support TPL-007-1.
Yes
No
: The tools necessary to justify casting an affirmative ballot do not presently exist, as explained above. Additionally, there is more involved here than just, “studies, assessments, and procedures.” Requirement 3 of TPL-007-1 states that any deficiencies identified in the study by the PC/TP are to be addressed by a Corrective Action Plan (“CAP”), which may include calls for, “installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment,” and “installation, modification, or removal of Protection Systems or Special Protection Systems.” It is unclear in the standard as presently written whether or not the modifications listed in the CAP will constitute binding obligations; Requirement 6 says that GOs and TOs will be given this document, but not that they need to implement it. We raised this point in the 5/20/2014 webinar, and the SDT advised that the intent of the Standard was to provide for a means of creating and sharing relevant information, not to give the PC/TP the ability to require a GO to take mitigation actions (including potentially capital projects). The SDT stated that requirement 3 will be modified accordingly, and we support this action. . Requirement 5 also creates concern in saying that PCs and TPs shall, “determine and identify the individual and joint responsibilities of entities in the Planning Coordinator’s area for performing the required studies for the GMD Vulnerability Assessment.” It had seemed that the scope of GO/TO studies is covered in R7, but R5 indicates that more responsibilities for analysis may be assigned in the future, and we

have no way of presently knowing whether or not the supplemental demands made will prove feasible. R5, like R3, is too open-ended.
Group
Florida Municipal Power Agency
Frank Gaffney
It is clear the GMD does not materially impact the BES for those portions of the BES further south in latitude. Causing these entities to perform studies just to show that there is no impact is a waste of time and expense. FMPA suggests making the standard applicable to only those entities for which the furthest north portion of their system is south of a certain latitude, e.g., 32 degrees North geographic latitude (equivalent to 41.61 degrees north geomagnetic latitude). Those entities whose systems are affected are required to share the results of their analyses with their neighbors, as such, those entities below a certain latitude can develop their operating plans based on how GMD impacts their neighbors. If the SDT does not agree with this approach, then, FMPA recommends that a variance be created for FRCC, which was entirely unaffected by the Hydro-Quebec event and would have minimal impacts for even something as major as a Carrington event even in accordance with overly conservative studies performed by Oak Ridge National Labs. FMPA notes there is no valid scaling factor (β) defined by the standard in Table 1-2 for peninsular Florida. In addition, regarding the content of the statements in 4.1.1 through 4.1.4, FMPA points out that the term “power transformer”, while being defined broadly by IEEE, is understood within the transformer manufacturing industry to mean something specific. Many entities consider “power transformers” to be different from “autotransformers” and “generator step-up transformers”. FMPA suggests clarifying the intent is the IEEE definition from ANSI C57.12.80, which is an umbrella under which autotransformers and GSU transformers fall as sub-categories, “A transformer that transfers electric energy in any part of the circuit between the generator and the distribution primary circuits”. Adding on to this, because the applicability discusses wye-grounded windings, suggest that the “brightline” at 200-kV be clarified to be “system voltage” or phase-phase voltage.
No
FMPA commends the SDT for developing a good approach to performing the studies, FMPA’s comments are not major. R8 uses the phrase “solely or jointly owned” (which we know is also used in other standards like FAC-008). FMPA suggests adding to this “solely or jointly owned … transformers … for which is it registered”. If a transformer is jointly owned, only one of the owners will be registered for that transformer, i.e., the registry criteria states that the TO is: “(t)he entity that owns and maintains transmission Facilities”; hence, only the joint owner responsible for maintenance of the transformer is registered for that transformer. Adding such language will help avoid confusion. Also, on Table 1, FMPA appreciates the difficulty in trying to draw a distinction between acceptable and unacceptable system behavior during a GMD event, e.g., item b. at the top of the table and bullet 4. at the bottom of the table are good additions. FMPA wonders, however, if bullet 4. prevents UVLS as a potential mitigation by the phrase: (non-consequential load loss) “should not be used as the primary method of

achieving required performance". Transformer saturation that does not threaten the health of a transformer may still threaten voltage collapse and UVLS may be a good mitigation; however, bullet 4 seems to prevent that. FMPA also notes that bullet 3. identifies harmonic effects as the reason Protection Systems may trip. We are concerned entities will interpret this as being direction to assume this would be the only reason for such protective action. We would assert that an even more common and prevalent Protection System operation that should be modeled would be tripping for under voltage conditions (such as at power plants) and tripping of transformers due to overheating (where such tripping is utilized), as well as excessive reactive flow in the system. FMPA suggests modifying the statement to say "…due to system conditions including (but not limited to) excessive harmonic current/voltage, abnormal voltages and reactive power flow, and excessive equipment heating".
Yes
Yes
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes, we agree.
No
The SDT respectfully requests the SDT to consider removing the term(s) "posture or posturing" and use language such as "changes to system configuration or configuration" to add further clarification in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. Two examples of this requested change follow: Rationale for R1. Current language: The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. Language for Consideration: The projected System condition for GMD planning may include adjustments to system configuration to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. A second example can be found on page 8, Table 1, Initial Condition: Current Language: 1. System as may be postured in response to space weather information, and then Language for Consideration: 1. System as may be configured in response to space weather information, and then Further, it is requested to have SDT clarify whether it is the SDT intention that there are any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? On page 8, Table 1, Steady State A: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Steady State A language: The

System shall remain stable. Cascading and uncontrolled islanding shall not occur. Language for Consideration: Cascading and uncontrolled islanding shall not occur. On page 8, Table 1, Steady State Performance Footnotes #4: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Footnote #4 language: The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Language for Consideration: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential 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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
The SDT is requested to consider modification of the Implementation Plan for TPL-007-1 – Transmission System Planned Performance during Geomagnetic Disturbances, Effective Dates. Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In addition to constructing the necessary models of one's own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. In addition, there is concern that it will take considerable time to calculate values of Rgnd, based on location dependent earth resistivity and ground mat design at each substation. If actual measurements of Rgnd are required, we can only practically measure Rgnd at in-service substations with all neutral connections and static wires in place. Are calculated values of Rgnd sufficient? The comments expressed herein represent a consensus of the views of the above named members of the PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Paul Didsayabutra
ColumbiaGrid

: The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC's respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC's to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis.
No
: While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Individual
Bill Fowler
City of Tallahassee, TAL
No. 1. While TAL believes it is the intent of the standard to include autotransformers, it should be pointed out that the standard specifically specifies "power transformers", which technically are different than "autotransformers". Additionally, "power transformer" is not defined in the NERC Glossary of Terms. 2. TAL believes the intent is to include transformers with a system voltage greater than 200KV, but the current language may not always be interpreted this way. In the applicability section of EOP-010-1 (Phase 1 of the project) the language specifies a terminal voltage of greater than 200KV. In the applicability section of TPL-007-1 the language has omitted "terminal voltage", and specifies a single high side, wye-

grounded winding of greater than 200KV. This may be interpreted as a phase to ground voltage (rather than a phase to phase voltage), meaning a 115KV/230KV, 3 phase, wye grounded autotransformer could be excluded from the standard. 3. Compared to Northern geographic regions, studies (including the 2012 NERC report Effects of Geomagnetic Disturbances on the Bulk Power System) show a very low probability (less than 0.0002%) for large geomagnetic events where dB/dt > 300nT/minute for the geomagnetic latitude of FRCC utilities. TAL recommends that a path be supplied for a region as a whole to submit for a regional variance/exemption from the requirements of the standard.
No
The TPL standard should better define which “Bulk-Power System transformers” mentioned in the NOPR, are to be assessed. If the intent is include autotransformers, it should be pointed out that as it is currently written, the standard specifically specifies “power transformers”, which technically are different than “autotransformers”.
No
It seems that parameters involved with GMD events and associated GIC’s are still being widely studied and disputed. It would be prudent to submit the “Benchmark GMD Event Data” for a peer review of experts based in the area of Space Science/Physics.
No
While TAL currently supports the phased implementation of TPL-007-1 as written, over the four year period, we believe that measures must also be taken to coordinate the phasing of the TPL-007-1 reliability standard with EOP-010, which was created during Phase one of this project. Without first receiving data from either the TPL-007-1 assessments or studies that allow for a geographic exemption to requirements in TPL-007-1, there will be no baseline from which to properly implent EOP-010. On measures: The language should be expanded to allow for posting the reports on regional websites (such as ftp sites) to fulfill the sharing requirements.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Yes
No
UI believes the implementation for R2 should clarify that the assessment is to be completed no later than the effective date of R2. For R3, UI does not understand why and the implementation plan does explain the reason for R3 (corrective Action Plan) to be effective 24 months later than the required R2 assessment. Many existing Standards require a CAP to be developed but none provide two years to create one. For consistency with TPL-001-4, PRC-

005-2, CIP-007, or CIP-014 the CAP for TPL-007 shoud become effective concurrent with or within 120 days of R2.
Group
MRO NERC NSRF
Joe DePoorter
The NSRF suggests the SDT revise the Purpose of TPL-007-1 to include R7 and R8 where GO and TO are required to perform assessment of thermal impact. Since the standard clearly states the TO and GO are responsible for the assessment of the impact of GIC on their transformers, the purpose of the standard should be revised to include this fact, recognizing that this is not just a TP assessment. Suggested Purpose: “Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon and establish requirements for assessing the thermal impacts of GIC on owned power transformers.” The standard is not clear on the proper sequencing of assessments between the TP and PC versus TO and GO. First, TP and PC should give powerflow results to TO and GO. Then TO and GO should provide their assessment of thermal impact specified in R7 to TP and PC. Next TP and PC should complete their assessments. The NSRF believes initial assessments of thermal impacts may well take more than 24 months, so to meet the sequences for all responsible entities either this timeframe needs to be expanded or provisions made for not completing thermal impacts for all transformers during the intial cycle. The NSRF also believes that some transformers have been built by manufacturers no longer in business and some transformers are old enough that manufacturers do not have sufficient information for TOs and GOs to complete thermal impact assessments. Provisions must also be made for such situations where thermal impacts cannot be completed and yet PCs and TPs need to complete their GMD Vulnerabililty Assessments within 24 months and, in some cases, at all.
Yes
: Although the NSRF agrees that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment, we recommend the SDT consider the following alternative language in requirments R1, R3, R5, R7, and Note 3: Table #1 The NSRF suggests the SDT remove the requirement to maintain ac System models in R1 to prevent the possibility of double jeopardy, as the requirement to maintain ac System models is already covered in Standard TPL-001-4 R1. The recommended wording for R1 is: “Each Planning Coordinator and Transmission Planner shall maintain (delete: ac System models and) geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. The System models shall include...” The NSRF suggests the SDT revise R3.1 as there may be other facilities such as distribution facilities for customers served directly by transformation from 200 kV and up that are

appropriate fo rinclusion in a Corrective Action Plan. The revised wording is noted below: List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include: • Installation, modification, retirement, or removal of Transmission and generation Facilities and any (delete: associated)other facilities or equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. • Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. • Use of Demand-Side Management, new technologies, or other initiatives. The NSRF suggests the SDT revise R3.2 as there may be other components of Corrective Action Plans such as distribution facilities for customers served directly by transformation from 200kV and up. The revised wording is noted below: Be reviewed in subsequent GMD Vulnerability Assessments for continued validity and implementation status of identified System Facilities, Operating Procedures and other components of Corrective Action Plans. The NSRF suggests the SDT revise R5 and corresponding change to M5 because there are other responsibilities beyond the required studies in R1 through R4 that require a resolution of responsibilities. The revised wording is listed below: Each Planning Coordinator, in conjuction with each of its Transmission Planners shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the Requirements R1 through R4 (delete:required studies for the GMD Vulnerability Assessment). In Requirement 6 the NSRF suggests the SDT consider potential R6 conflict with Critical Energy Infrastructure Information (CEII) and CIP requirements relating to reliability issues. A recommended change is noted below: Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need ", permission to receive assessments," and submits a written request for the information within 30 days of such a request. The NSRF suggests the SDT consider clarifying that the thermal impact assessment may not need to be completed in each cycle for each transformer. The revised wording is listed below: Each Transmission Owner and Generator Owner shall have a current valid assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The NSRF believes there is no reasonable way to conduct the harmonics assessment required by Note 3, Table 1 at this time. We suggest the requirement be removed or the SDT describe how the harmonics assessment can be completed in the guidance document. Also, we suggest that if Note 3 to Table 1 is retained, it be changed to: Protection Systems may trip due to the effects of harmonics. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible to tripping. In the event harmonics assessment tools are not available, known or assumed values may be used, along with the assumptions utilized. The NSRF believes that the term BES should be added to R7 and R8 and read as: R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term

Planning] R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]"
Yes
The NSRF supports the proposed Benchmark GMD event, but 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.
No
The NSRF believes initial assessments of thermal impacts may well take more than the 3 years (if the revised language for Note 3 is not accepted) that are allowed for R7, so either this timeframe needs to be expanded or provisions made for not completing thermal impacts for all transformers during the intial cycle. We also believe that some transformers have been built by manufacturers no longer in business and some transformers are old enough that manufacturers do not have sufficient information for TOs and GOs to complete thermal impact assessments so provisions need to be made for that as well in R7. Also see the discussion in Question 1 above concerning sequencing issues in the implementation process.
Group
PacifiCorp
Sandra Shaffer
PacifiCorp does not agree with the proposed threshold for transformers. The requirement should be based on whether the transformer is classified as Bulk Electric System AND 200 kV or above high side connection. The threshold should result in the inclusion of only "critical Bulk-Power System facilities." The proposed threshold would bring numerous non-critical distribution substation (230-34.5 kV and 230-12.5 kV) facilities into the analysis, as well as non-critical 230-69 kV local transmission facilities the loss of which would have no impact on the Bulk Electric System. Because a GMD event is an interconnection wide event and its impacts could be throughout the interconnection, it requires accurate modeling of the whole interconnection wide system to calculate the GIC currents. PacifiCorp believes that the responsible entity to perform the functions required in the draft standard should be the Regional Reliability Organization (RRO). By performing the study at the regional level, the

assumptions, findings and subsequent recommendations would be applied consistently across the region. Also, with the RRO performing the studies, it can be ensured that the mitigation action taken by one TP does not negatively impact the neighboring TP. As a practical matter this study can be performed by a task force of Planning Coordinators, Transmission Planners, etc. acting on behalf of the RRO.
No
Per the drafting committee webinar presentation on 05/20/2014, they would like the PCs and TPs to perform outages of transmission elements or generators that have a potential to trip during a GIC event due to harmonics as part of the GMD Vulnerability Assessment. To date, there is no commercial software available that determines the harmonics and its impacts on transmission element. Since it is therefore difficult to determine whether or not a particular transmission element will be tripped or not; the drafting committee need to provide guidelines as to what different outages a TP and/or PC needs to take as part of the GMD Vulnerability Assessment until such capabilities are developed/available in commercial software.
Yes
PacifiCorp supports the proposed Benchmark GMD event, but we are concerned that data in Table 1-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the earth model. 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.
No
PacifiCorp is concerned that the thermal impact assessment may require test information that is not available. This could include old transformers for which manufacturer records are no longer available. There needs to be a provision for these situations to ensure consistent modeling applications. Also, it is not clear whether the result of the assessment of thermal impacts would be incorporated into the study described under R2. If the thermal impacts need to be considered in the study described by R2, then the timeline for R2 needs to be expanded. As GMD is an interconnection wide event, in order to calculate the GIC, the responsible entity should be required to have a model for the whole interconnection. The draft standard should provide 18 months to the applicable entities to allow collection of the data required to produce the dc system model and ac system models (both electrical and thermal) to perform GMD Vulnerability Assessment. Requirement 1 of TPL-007 should be effective 18 months after the FERC effective date.
Group
ACES Standards Collaborators
Ben Engelby
(1) We have a concern with the responsibilities assigned to both the Planning Coordinator and Transmission Planner concurrently. The drafting team should apply a single function as responsible to maintain models, complete vulnerability assessments, and completing Corrective Action Plans. Other standards projects attempted to assign a shared responsibility

to both the PC and TP, which led to confusion regarding what roles each entity was ultimately responsible for performing. We recommend that the PC should be the entitiy responsible for maintaining the GMD models and performing GMD Vulnerability Assessment since it is the entity that has a wide area view and GICs are not bounded by transmission planning areas and it has the processes and tariff requriements in place already to coordinate with its Transmission Planners. For those areas without these tariffs and processes, the PC and TP are typically the same entity. Furthermore, by requiring a single entity such as the PC it avoids the compliance confusion of who actually is responsible and avoids the need to write requirements such as R5 that includes superfluous language such as “in conjuction with each of its Transmission Planners.” This language is superfluous because the requirement apply only to the PC and cannot be enforced on the TP and should be removed. (2) Since the applicability only applies to the high side of the power transformer, this raises the question if the standard intends to expand applicability beyond the BES. 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. Is the intent to expand the definition beyond the BES? Please make clarifying changes to the standard to clear this issue up.
Yes
We believe the drafting team provided reasonable technical justification to address the directives in FERC Order No. 779. However, we have a few overarching concerns that are stated in questions 3 and 4.
No
(1) Requirements R6 and R8 meet Paragraph 81 criteria and should be removed. These requirements only deal with data requests and submittals, which is one of the criterion of Paragraph 81. Please revise or remove these requirements from the standard. (2) 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. Will there be a limit on the non-consequential load loss similar to the resolution of the TPL footnote b issue?
No
(1) A four year implementation seems reasonable on paper, but the drafting team needs to take into account the other NERC standards that are going through implementation periods during this time, the significant learning curve of performing these new GMD studies, and the time to develop these new models using limited resources. The new definition of BES will bring in new assets, which will require a two-year implemetntation for all applicable standards. PRC-005-2 will be going through a multi-year implementation and the CIP version 5 standards are also being implemented during this time. There are other studies and assessments that need to be performed for physical security. Along with these high-profile standard projects, there are numerous other standards that take effect as well, which is a tremendous burden on each entity’s resources. Building these new models and learning to performing these new studies is not small effort and may require additional staff and/or consultants that could have backlogged schedules due to the demand for their resources. For

a small entity where the planning engineer may wear multiple hats, this will be quite a significant challenge. For these reasons, we recommend a longer implementation plan for smaller entities so applicable registered entities have enough time to focus the requisite time and resources to each of these standards implementation. Further, due to the expense of acquirinig tools and performing assessments, there should be additional time so entities are successful in executing the required tasks to mitigate GMD events. (2) Thank you for the opportunity to comment.
Group
Edison Electric Institute
Mark Gray
Yes EEI believes that the functional entities identified in the standard have been correctly identified.
Yes
Although EEI agrees that the technical guidance for the Vulnerability Assessments meet the directives of Order 779, we do have concerns that complete guidance may not have been provided in the standard for the Corrective Action Plans necessary to mitigate any BPS impacts which might be revealed by a GMD Vulnerability Assessment. For this reason, we suggest that the drafting team consider adding requirements within the standard requiring that GMD Vulnerability Assessments be issued to the responsible Reliability Coordinator in order to ensure any operational issues are properly understood and addressed. EEI further notes that in Table 1 (Steady State b), the proposed standard allows for Consequential Load Loss and generation loss as a consequence of P8 planning event. The term “load loss” should be used instead to allow for the loss of both Consequential and Non-Consequential Load. Because the P8 planning event is not fault related, we feel that use of the term “Consequential Load Loss” alone is inappropriate.
Yes
EEI strongly supports the proposed benchmark GMD event believing it to be technically sound reflecting good engineering practices as typically employed by electric utilities broadly. In FERC Order No. 779, the Commission directed NERC to “identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk Power System.” (See P54, Order 779) Included in that directive were requirements to include varying severity, duration, geographic footprint of the GMD, GMD intensity variations due to latitude and electric system configuration relative to magnetic field orientation. In our review of both the draft TPL-007-1 standard (Attachment 1) and the referenced Benchmark Geomagnetic Disturbance Event Description (whitepaper) dated April 21, 2014 we find all of these requirements to have been fully addressed in a manner that we believe to be reasonable and defensible based on the current state and understanding of severe space weather and its impact on the BPS. As part of our review, we found that the SDT based their Benchmark event on a 1 in 100 year event, which we agree exceeds normal utility practices by a factor of 2 for earth based weather related catastrophic event analysis. Given Industry experience with these types of events, Industry designs based on traditional engineering

analysis have been shown to be effective over time. In contrast satellite data supporting the effective observation of the sun and supported by efforts to develop a firm understanding of GMD/GIC impact on a modern power grid only spans a relatively short timeframe, in comparison (i.e., less than 30 years). This along with other limitations led the SDT to employ statistical analysis typically associated with extreme event analysis, which has been demonstrated effective in other Industries and we believe provides a useful and effective method for extrapolating a defensible Benchmark event for the Industry relative to GMD. EEI notes that one of the major enhancements to the most recently proposed Benchmark was the averaging of localized extremes. In the work conducted by the SDT, it was discovered that localized extremes during GMD events is common and supported by measured magnetometer data. Given the Benchmark is intended to address the “wide-area” effects of a GMD event, the SDT developed methods to address this issue. The result was the spatial averaging of data over a 500 km area. Although this does have the effect of lowering the projected Benchmark, we believe this to be reasonable and appropriate given the grid is resilient and designed to withstand some localized and pocketed outages which could occur during a GMD or similar extreme event. Such methods will ensure that reasonable and prudent measures are taken to protect the grid from instability and cascading failure as directed by the Commission in Order 779.
Yes
EEI supports the proposed Implementation Plan as proposed believing that it provides sufficient time for entities to effectively assess and develop Corrective Action Plans to mitigate any uncovered impacts due to GMDs. Although the timeframe does on the surface appear to be long, EEI cautions against the shortening of this Plan given the maturation expected in space weather and geomagnetic sciences, the data derived from these, and inclusion of these advancements in performing GMD vulnerability assessments.
Group
DTE Electric
Kathleen Black
Yes, we agree
No comments
No comments
No
Comments: It is not clear from the Implementation Plan for R7 and R8 if all identified mitigation work is to be completed within the 36 month time frame or only the assessment is required and any mitigation or corrective action plans are merely identified. It is not reasonable to expect mitigation work per R7.3 to be completed within the 36 month time frame. Also, it would seem prudent to coordinate mitigation measures on a regional basis. For example, shouldn’t placement of neutral GIC blocking devices be coordinated across the region by the PC and TP? It appears from R1 and R6 that the PC and TP are required to model the GIC system and provide GIC currents (as per Attachment 1) to the TO and GO for thermal

assessments. Perhaps R7.1. can be changed to clarify who is providing all the necessary GIC current information that is needed by the TO and GO.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Agree
Yes
Note that there is a discrepancy between multiple figures throughout the proposed Standard and supporting documentation, where some illustrations depict a scaling factor (β) for the majority of the FRCC Region and other illustrations do not depict a scaling factor at all for the same Region. It appears from the USGS linked Regional Conductivity Map that is cited in the supporting documentation (see here: http://geomag.usgs.gov/conductivity/), that the maps are based off of findings from the Fernberg, et al. 2013 research paper. Reviewing the USGS conductivity maps, one is unable to select South Florida to reveal the conductivity analysis for that region based off of Fernberg, et al. 2013. Seminole suggests that the Standard should not be posted again until the SDT has determined and posted on the USGS website the conductivity(ies) for the entire FRCC region along with any scaling factor(s) for the entire FRCC region using the same methodology utilized for the rest of the Regions. In the alternative, Seminole suggests that the FRCC Region be exempt from this rulemaking until proper studies can be performed and posted that cover the FRCC Region.
Yes
It appears that the studies were based off of a 1 in 100-year event, i.e., benchmark event. In addition, it appears that the supporting documentation concludes that local GMDs do not have a wide area impact, i.e., do not directly affect wye-grounded transformers far away. If this is correct, the possibility of a local GMD occurring within the FRCC region and developing geomagnetically induced currents directly affecting a wye-grounded transformer in the FRCC Region is less than 1 in 100 years, i.e., less frequent than 1 in 100 years, correct? Further, the benchmark event for the technical basis of this Standard appears to be the 1989 Quebec event. In addition, it appears that the supporting documentation concludes that local GMDs do not have a wide area impact, i.e., do not directly affect wye-grounded transformers far away. Can the drafting team post supporting documentation in the application guidelines section of the Standard or a white paper that details GMD events as strong or stronger than the 1989 Quebec event that have occurred in the southern regions of the U.S., such as in Texas and Florida?
Yes
Individual
Jo-Anne Ross
Manitoba Hydro

Yes. Section 4 Applicability, 4.1 Functional Entities: The standard does not specifically include loads entities who may own a 200 kV or higher transformer. In Manitoba major load customers may interconnect to the transmission system at the 230 kV level and own the transformer. Such entities must also be included in the standard.
Yes
Consider amending the wording for R6 to address confidentiality concerns: “Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to functional entities within its own planning area that has a reliability related need and submits a written request for the information within 30 days of such a request.”
No
Requirements R2 and R3: The analysis proposed is not consistent with the phenomena. Transformer thermal analysis (R3) is to utilize the 12 hr benchmark waveform to determine the temperature increase in the transformer this is appropriate due to the time constants involved. It is not appropriate to take the instantaneous peak electric field magnitude for a steady state simulation (R3). The Peak electric field only occurs momentarily (figures 2 and 3). For steady state analysis it is appropriate to take some averaged or mean value for the peak electric field. If the intention of the standard is to analyse the peak instantaneous electric field values then an electromagnetic transient simulation is appropriate. Requirement R2----2.2 states that the analysis shall use the benchmark GMD event described in Attachment 1 of the standard. This is a uniform 8 V/km electric field to be scaled based on geomagnetic latitude and earth conductivity. This benchmark is not based upon sound science. The development of this benchmark event is documented in Appendix I of “Benchmark Geomagnetic Disturbance Event Description” and suppose to represent a 1 in 100 year event. The magnetometer data used for this analysis originates from the IMAGE magnetometer array located in Finland. The main purpose of this analysis is to identify 1.) The maximum peak electric field level and 2.) The reference waveshape. Technical issues with the analysis in Appendix I of “Benchmark Geomagnetic Disturbance Event Description” are: a. There is no independent peer review of the methodology or data set used develop the 1 in 100 year event, b. The data set used for the peak electric field analysis comes from the IMAGE magnetometer chain in Finland using a 21 year data set (1993 to 2013). At a minimum equivalent analysis must be completed using data from the CARISMA magnetometer chain in Canada to confirm that the data set is relevant and that the analysis is correct. c. There is no clear documentation on how IMAGE magnetometer data was manipulated to generate statistics for the 1 in 100 year event (did you simply normalize the bin counts by 21 years and then multiply it by 100?), d. Data provided does not support the proposed GMD benchmark event. Figure I-2 tells us that over a period of 100 years we would expect one 10 second interval to have a peak electric field of 3 to 8 V/km. There are 3 billion 10 second time intervals in 100 years. Thus the probability for 3 to 8 V/km to occur is 3x10-10!!! e. From the document seems that 8 V/km value was derived by visually extrapolating the curves in Figure

I-2. This is unscientific and not appropriate. Please provide a polynomial fit to the data and extrapolate using sound mathematical principles. f. Extreme value analysis does not support the 8V/km. The document argues why extreme value method (4) is preferred over (1), (2) or (3). Method (4) provides a peak electric field of 5.77 V/km! Two decimal places suggests an accuracy in the 100th's. The statistics is already in the 95% confidence sound engineering judgment would round this value to 6V/km. g. The magnetometer chain (IMAGE) used to develop the benchmark is at the same geomagnetic latitudes as Manitoba therefore the peak electric field over Winnipeg (60 degrees geomagnetic latitude) is the value found using the extreme value analysis (5.77 V/km). Instead of specifying a specific benchmark that is not supported by scientific peer review (as is the case with the proposed benchmark in "Benchmark Geomagnetic Disturbance Event Description", please rewrite R2 – 2.2 as: "2.2 Studies shall be conducted based on the approximate 1-in-100 year benchmark GMD event described in Attachment 1, a planner can substitute a technically justified 1-in-100 year benchmark GMD for its planning area where available."
Yes
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
It appears that there may be a possible reliability gap with R3 and R7. If the applicable entities (PC, TP, GO or TO) have identified a corrective action plan under R3 or suggested actions under R7, there is no specific requirement for an entity to implement the corrective action plan or suggested actions. Compliance with the Standard, as currently written, may not result in reduction of an identified risk to the BPS. Consideration of adding a requirement to implement corrective actions is requested.
Group
ISO/RTO Council Standards Review Committee
Gregory Campoli
Yes
No
• Requirement R3 requires the development of a Corrective Action Plan. Current TPL standards require Corrective Action Plans for N-1 and N-2 conditions but do not require them for N-3 and beyond. If impacts from a GMD event create N-3 or beyond conditions, this standard goes beyond existing practice to require Corrective Action Plans. Shouldn't there be

consistency within the standards in the area? • It is not overly clear how to apply the proposed simulation to meet the standard. Because of this, the simulations run by various entities may not be consistently done. Since this is a new type of analysis in the planning process, it needs to be well understood by those performing the analysis. How the event is modeled, what equipment trips and the timing of this is critical to the simulation, but doesn't appear to have been fully vetted. These concerns highlight the need that more guidance on the approach is needed Also, has the GIC software that is commercially available been benchmarked against one another to ensure consistent results? If so, was the size of the system sufficiently robust to ensure similar accuracy on actual large systems? Additionally, there is contradictory language between using short-term cases, but applying for long-term horizon. • R1: The sentence: "This establishes Category P8 as the normal System condition for GMD planning in Table 1." is unnecessary. R1 requires the responsible entities to develop a system model for performing the studies needed to complete its GMD Vulnerability Assessment. Category P8 is an event or contingency to be applied, not a system model whose details are provided in Table 1. We suggest to remove this sentence to avoid confusion. • R2: The sentence: "This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis." is unclear. The part that says: "document assumptions and document summarized results" is confusing. We are unable to clearly understand whether the requirement asks for using "documented assumptions" and "documented summarized results" (of previous studies), or to ask for "documenting assumptions" and "summarizing results". The sentence needs revision to improve clarity. Footnote 4 in Table 1: The second and third sentences are misleading. (i) The second sentence indicates that Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed [i.e. allowed] to meet BES performance requirements during studied GMD conditions, but it stipulates that such conditions should not be used as the primary method of achieving required performance. There is no criteria or guideline as to what constitutes "primary method" of achieving required performance. When such actions are allowed, Planning Coordinators and Transmission Planners will in their GMD Vulnerability Assessment include these actions in the studies/simulations. How would these entities determine whether or not such actions are the primary method of achieving required performance when other means are applied to meet performance targets? We suggest to remove the phrase "but should not be used as the primary method of achieving required performance" to avoid confusion. (ii) The third sentence indicates that "GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event." The condition that "Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event" is not specified and cannot be adequately assessed or measured. In other words, what constitutes "minimized" is a subject of debate. We therefore suggest to remove this part to avoid confusion.
No
• The event needs to be better explained as to the degree of its conservativeness and also how wide-spread the potential impacts could be. Has any research been done to determine

that if the event is conservative, how significant the Corrective Action Plans would be? And if those Corrective Action Plans are significant, is this level of conservatism appropriate. A better understanding of the benchmark GMD event needs to be provided and a better explanation of how GIC flows are calculated and used in steady state analysis is needed. Clear step-by-step calculations would be helpful to provide consistency amongst all regions.
No
• The transformer data that is needed to develop the DC transformer model is not typically provided to the TP/TO at time of delivery. Some transformers may need to be tested as the manufacturers may no longer have the necessary data due to the age of the transformers. New York has approximately 100 substations with high-side transformers at 200kV and above. Doing this testing may require an outage of the transformer and if so, it may take significant time just to get the tested information. If estimated values are used, the results of the analysis could be suspect which would be a significant concern especially considering the time and expense that would be required if Corrective Action Plans were warranted. • It is unclear what data is needed for input into the commercially available software until a demonstration is provided. If actual data is not available and estimated values are used, how can corrective action plans be proposed? These plans would have to be checked against potential risk to reliability. • The timeframe may not be realistic as it may take considerable time to get the database information from the owners of those facilities. It is extremely difficult to determine this time given the complexity it may take to get this information. 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 could easily take longer than those prescribed in the standard. • The Standard Drafting Team needs to consider moving out the implementation plan at least another 6 months, and consider rearranging the implementation order. Some regions of NERC has not fully developed a GIC model. ERCOT believes that it would take additional time to complete the GIC System model. Requirement 5 will take additional time to formulate agreements between TPs and PCs. In areas where GMDs have not historically been an operating issue, some TPs and PCs will have to secure additional expertise and tools to develop the model and complete the assessments. • The SDT needs to consider rearranging the requirements in the implementation plan in order to develop a valuable assessment. Results from requirements R7 and R8 are needed to execute R2, therefore consider switching the sequence of requirements with adjusted effective dates in the implementation plan or provide clarity otherwise.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC Planning Standards Subcommittee
Group
Colorad Springs Utilities

Kaleb Brimhall
Southwest Power Pool Comments
To better ensure coordination and reduce wasted software investment and resource expenditures, we suggest consideration of adding the RC or regional entity and requiring a regional model and study development. For example, WECC or the RC would develop the models and studies with the assistance of the other functional entities included in this proposed standard.
No
We still have concern that this effort is not merited based on the provided data. Especially since the peak solar flare cycle shows us starting into lower magnitude and frequency period based on historical data.
No Comments
See comments for Question 1 - Possible alternative to high investment for software and resource expenditure on a individual entity basis would be to assign requirements to the RC or regional entity to create more comprehensive studies and models which would also better utilize resources. In the corrective action plan section it references “operational procedures.” Are operational procedures going to be acceptable for long term solutions to identified vulnerabilities? Concern is that cost for mitigation could be very high with a very low probability. Thus the ability to mitigate via operational means could be effective and cost effective. The thermal studies should be required as part of the vulnerability assessments, and not be separate requirements. It appears that thermal studies are separate and distinct from vulnerability assessments, and think that thermal assessments must be a part of the vulnerability assessment for it to be complete. Requirement 6 should be by request only. We should avoid the sharing of information without a verified need and request for all parties. Making sharing of results and corrective plans by request only eliminates unnecessary paperwork burden.
Individual
Dan Inman
Minnkota Power Cooperative
MRO - NERC Standards Review Forum (NSRF)
While we support the NSRF's comments, we would also like to add: The requirement in R7 to complete a thermal impact assessment of GIC on 230 kV high-side Y-connected transformers. Removing this requirement for non-BES, radial load serving transformers would be prudent as it would reduce the number of transformers to be assessed thus reducing the iterative process between the GIC assessment and thermal impact assessments. Loss of these radial, load-serving transformers will not impact systems cascading. The following language is proposed: R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7

for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]" Another methodology would be including a transformer size threshold such that radial load-serving transformers of 100 MVA or less would not be assessed.
Individual
Jay Teixeira
Electric Reliability Council of Texas, Inc.
No
It is unclear what additional items constitute "geomagnetically-induced current (GIC) System models" as compared to the "ac System models". It appears from the items in 1.1 to 1.6 that only 1.2 represents the additional items required to create a "geomagnetically-induced current (GIC) System model". Is this correct? If the corresponding "ac System model" represents a specific date/hour then are the outages included in 1.2 those outages that are in effect during the simulated date/hour that have a duration of at least six months?
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No. Within FERC order 779 P.67 it states, "The NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate assessments across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness." The logical choice for applicability, based on the FERC order, would then be PCs and RCs not TPs. Ultimately the RC has the widest range of perspective within the region and should therefor be the final entity in the chain. Tri-State would suggest that it should be the BAs/PCs responsibility to come up with initial assessments to their area and to have the PCs and RCs work together to determine the ultimate assessment for the region.
No
Tri-State does not agree. While we appreciate the documents available, we would like to see and review the "Transformer Modeling Guide" which is not yet available, before we can fully

assess this. Until then we do not believe the requirements are supported by the technical guidance.
Yes
From the technical papers that support it, Tri-State can agree with the Benchmark GMD event. However, we continue to be against having an industry standard for GMD as the Benchmark event, supported by the technical papers, is a 1 in every 100 year event and it is unreasonable to ask industry to do continual planning for such a rare event.
No
Tri-State has some older power transformers from manufacturers that are no longer around and envision great difficulty in calculating or estimating the harmonics, thus the reactive losses, and the thermal assessment. With the lack of some vital information to these assessments, Tri-State believes this will be time consuming and difficult to complete. Tri-State has a large concern associated with gathering the model data in time of the effective date. The completion of the study work within 2 years will greatly depend on how system-wide complete modeling data is obtained. Studies should be run in a coordinated manner and the RCs should play a major role in doing so.
Individual
Frederick Faxvog
Emprimus LLC
Agree
Terry Volkman and John Kappenman and Prof Dan Baker
Individual
Bill Temple
Northeast Utilities
Yes
Yes
Yes
NU would like for the SDT to provide the basis for going from 3 V/km to 8 V/km with respect to the field amplitude.
Yes
Individual
Paul Robert Hayes
CEMTACH
Agree
Agree with Foundation for Resilient Societies' comments

Comment on Correct Characterization of Reference Geomagnetic Field Disturbance

In the May 20, 2014 NERC TPL-007-1 Technical Conference, a slide (Figure 1) was presented that attempted to characterize the dB/dt intensity of the Geomagnetic Disturbance Reference Field. The calculation of this peak dB/dt is in error and will be discussed further.

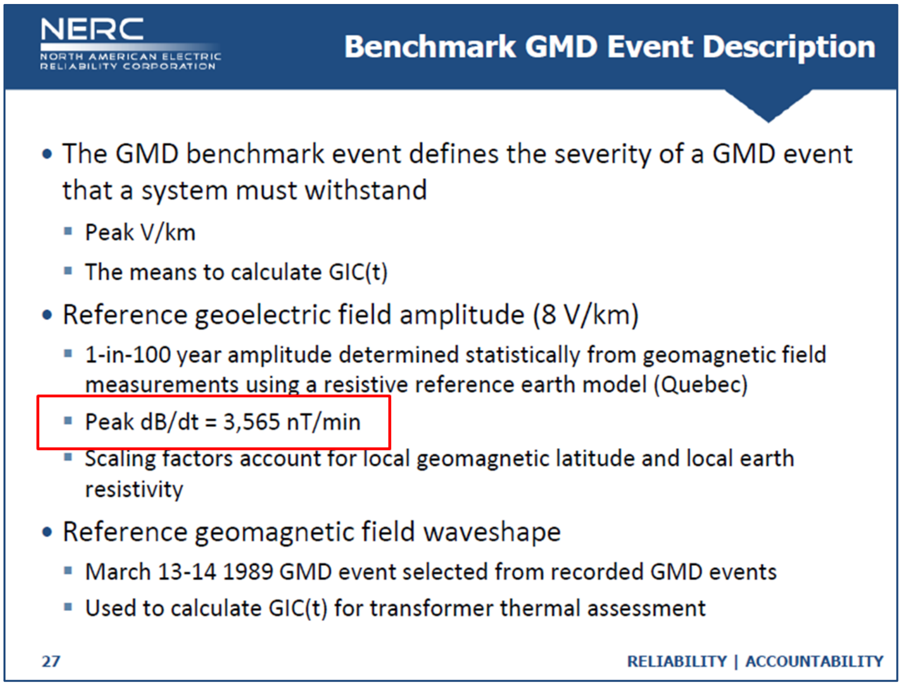

Figure 1 – Slide 27 from NERC May 20 Tech Conf noting Peak dB/dt of reference field

The NERC Geomagnetic Disturbance Reference Field was publicly provided on May 6, 2014 and has a time step cadence of 10 second time steps between data points. Figure 2 provides a plot of the total horizontal rate of change of change of the geomagnetic field (dBh/dt) in terms of nT per 10 Second time steps. As shown in this graphic summary, the peak dB/dt approaches ~600 nT/10sec (more exactly, it reaches a peak of 594 nT/10sec at time step 27,870 seconds). The NERC GMD Standards Drafting Team apparently used the simple multiplication of 6 times the 594 nT/10sec to derive the 3,565 nT/min referenced in Figure 1. This is in error and does not obey the averaging protocol used in geomagnetic observatories around the world to derive the intensity observed in nT/min. It is only possible to reach a 3,565 nT/min intensity if the actual total nT change is equal to 3,565 nT over a time span of a minute duration.

In many cases the sharp ~500 to ~600 nT/10sec changes are not sustained over a time duration of a minute, hence the simple multiplication of these values by 6 to convert to nT/min will overstate the intensity greatly in these situations. This overstatement is clearly the case in the NERC Reference Field. If we take the reference field in 10 sec time steps and average each minute the dB/dt into true nT/min rate of change, the resulting dB/dt intensity is as provided in Figure 3. As shown in this proper conversion, the peak dB/dt is only ~2000 nT/min, not the NERC claimed 3,565 nT/min. It should also be noted that this adjustment further shifts the time point of this peak to a time that is much later in the reference storm, which is also at a time consistent with the estimated peak geo-electric field. Therefore this NERC characterization is incorrect and greatly overstates the equivalent nT/min intensity of the reference waveform and is also inconsistent with the peak geo-electric field data.

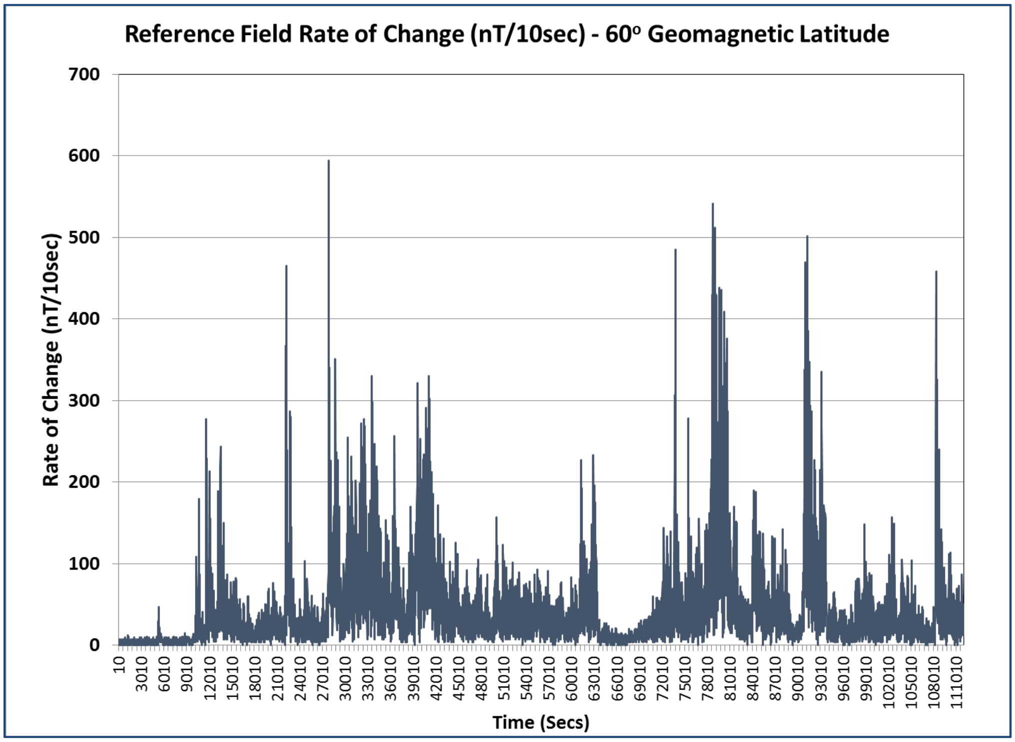

Figure 2 – Rate of Change of NERC Geomagnetic Disturbance Reference Field in nT per 10 Seconds.

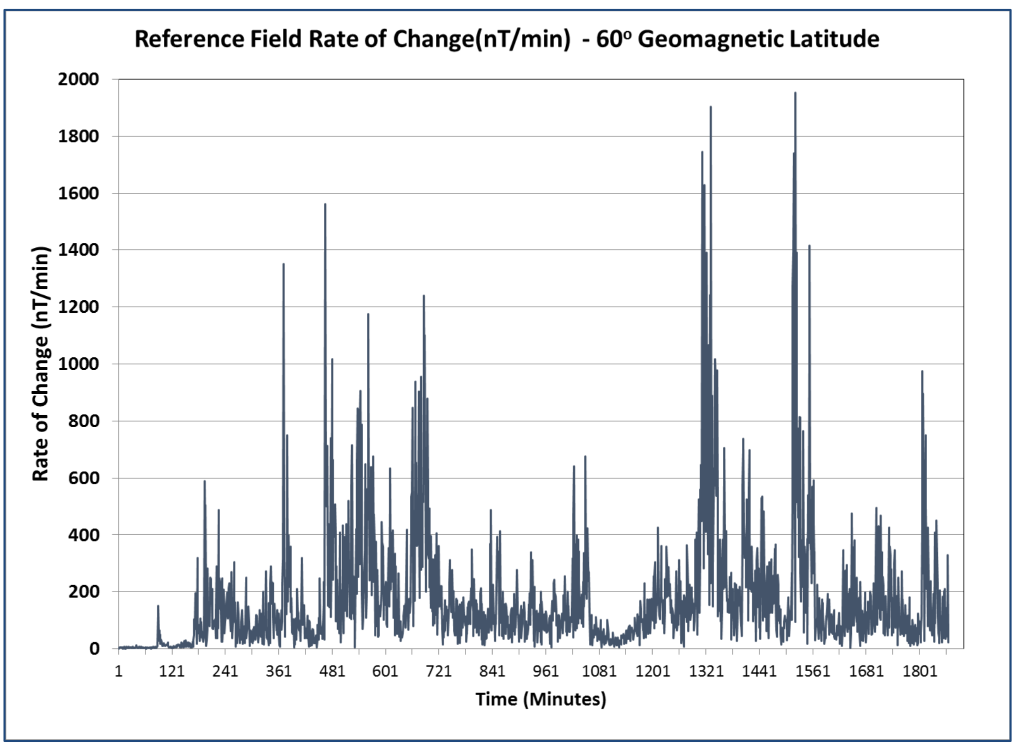

Figure 3 – Correct Rate of Change of NERC Geomagnetic Disturbance Reference Field in nT per Minute.

Comment on Instances of Observed Geo-Electric Field Intensity Greater than NERC Standards

The NERC Draft Standard TPL-007-1 provides a simplified formula based upon a Reference Geo-Electric field to derive the "Calculated Peak Geo-Electric Field" for a specific location, with their stated objective being to provide a conservative value of the peak geo-electric field for the reference storm.

To examine the merits of this "Calculated Peak Geo-Electric Field" method it is reasonable to compare the results from this method with the measurement of a known geo-electric field intensity from a moderately severe storm event (~1-in-10 year to 1-in-30 year event). On August 4, 1972 a large scale dB/dt occurred over the western half of North America. Figure 1 provides a reconstruction of this event (C. W. Anderson III, et. al. Outage of the L4 System and the Geomagnetic Disturbance of 4 August 1972).

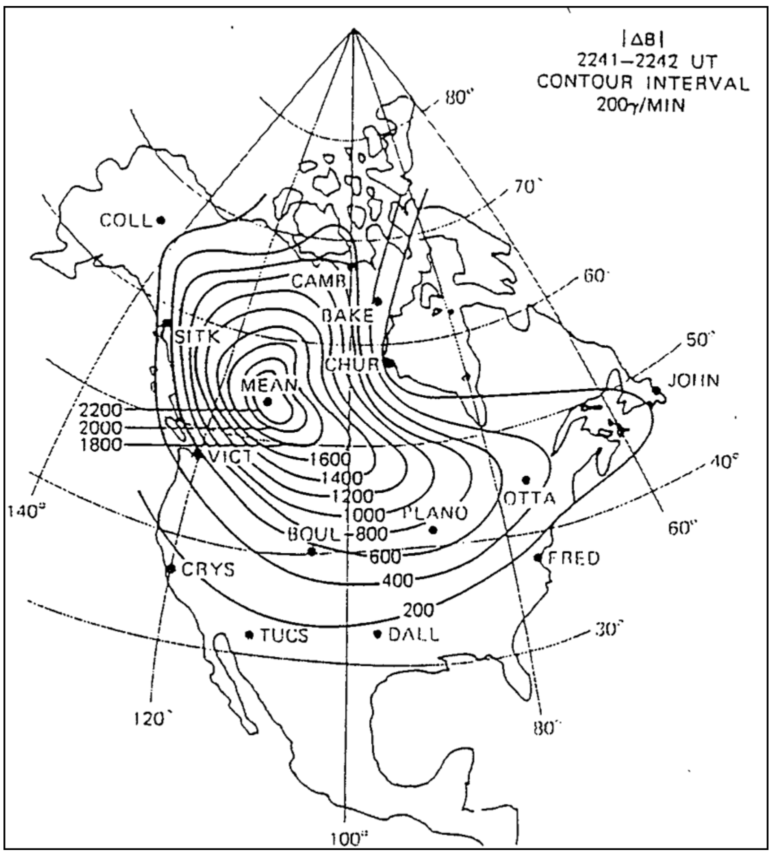

Figure 1 - Morphology of storm from ATT Analysis of Storm – Anderson, Lanzerotti, et.al.

This sudden dB/dt caused a AT&T Communication Cable failure between Plano, Illinois and Cascade Iowa due to an intense geo-electric field which affected a critical subsystem on this infrastructure. The authors of this report concluded that the geo-electric field intensity had to be at least ~7 V/km to cause this upset. Further from this reconstruction, the dB/dt intensity in the region of the L4 Cable system was estimated to be approximately 800 nT/min. The distance between Plano and Cascade is ~220 km, making this an infrastructure which is fully integrating the geo-electric field over meso-scale distances and comparable to the scale of similar infrastructures on electric power grids. Hence this is an important reference and benchmark point for this region of the US.

Using the "Calculated Peak Geo-Electric Field" method, as defined by NERC in the formula of E peak= 8 x αx β(in V/km), a peak 1-in-100 year geo-electric field can be derived for this same location in the Cascade/Plano region of the Midwest. Both Plano and Cascade are located at ~52^{o} geomagnetic latitude. This location would fix the Alpha (α) ratio as being ~0.4, the location for the Beta (β) is "Prairies" ground model with a ratio value of 0.96. Using this approach, the Peak Geo-Electric Field for the NERC 1-in-100 Year Reference Field would only be ~3 V/km, which is ~2.3 times smaller than what actually occurred during the August 4, 1972 event at this same location. As this comparison illustrates, the proposed NERC standard will significantly understate the Peak Geo-Electric for this region.

Section 1. - Analysis of Transformer Failure Rates in US and Association with Geomagnetic Storm Events

Examinations carried out using publicly available data from an IEEE GSU Transformer Failure Survey clearly show associations between prior GMD disturbances and failures of these transformers and was reported to the US FERC in a study performed by Storm Analysis Consultants. This report illustrates that the major root-cause of failures of these transformer failures over the period of 1980-1995 is likely due to specific GMD events. Further these GMD events were much smaller than the most severe GMD events that are now understood to be possible to occur across the US bulk transmission electric grid. Figure 1-1 provides a comparison plot showing Geomagnetic Storms (top as measured by Ap* index) and discrete GSU transformer failures that are reported over a period from 1980-1995. Three major storms (July 1982, Feb 1986 and March 1989) all produce increases in transformer failures in their aftermath. Further these scale in a dose/response rate to reported dB/dt levels of each storm. The highest being the 1989 storm, the next highest the 1982 storm and last being the 1986 storm.

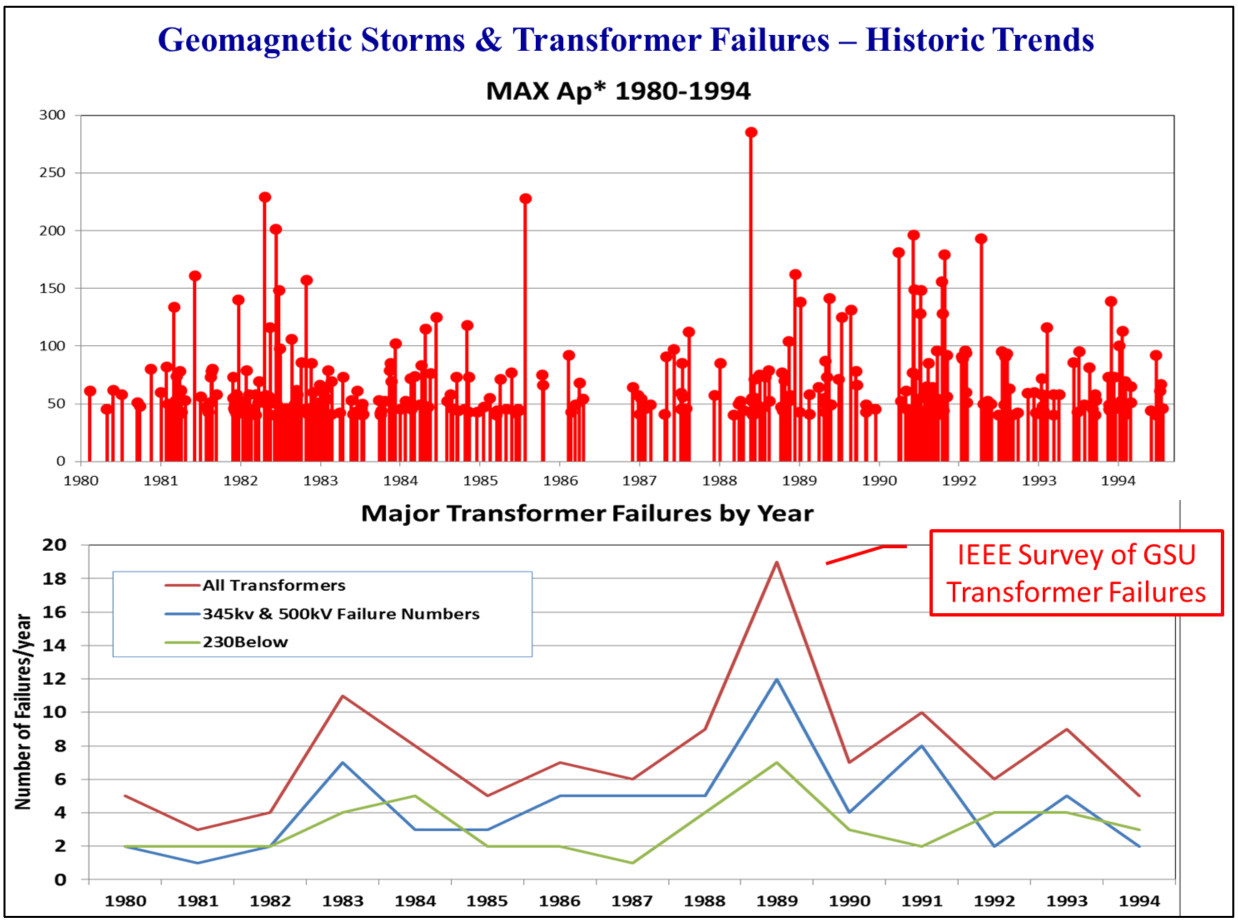

Figure 1-1 – Correlation of Geomagnetic Storms with reported GSU Transformer Failures.

Because the survey included added information on the failure events, it is possible to understand the consequential dimensions of these failures in more detail. For example all of these events Post 1989 are major failures, requiring replacement of the transformer. Further when looking at the failure, other consequential impacts where noted, the most important being that for 27% of all reported failures resulted in a major transformer/substation fire event as well. This increased the degree of consequential damage due to major catastrophic or collateral damage due to fires, tank rupture and/or oil expulsion.

In looking at the participants in this voluntary IEEE survey, the analysis showed that they constituted less than 50% of all US utilities (as measured by MWHr sales). Therefore it is likely that some failures have not been reported or included in this survey and the statistics are understating the degree of vulnerability possible from future larger storms. Other data bases do confirm this gap of reported failures as the US NRC maintains a database of Licensee Event Reports (LERs) for all nuclear power plants in the US. Over this same period of time, a number of LER reports were filed involving GSU transformer failure, that were not included in the voluntary IEEE Survey report. For example just in the few years in the aftermath of the March 1989 storm, eight (8) separate US NRC LER reports also noted GSU failures (that were not included in IEEE Survey). It is also possible that Nuclear Plant GSU failures may have also occurred that did not result in a reactor scram, which is the trigger for LER reporting under license requirements. Hence the failures reported in both of these data bases are a minimum and could be even larger due to these participation gaps. It should be emphasized that this analysis only concentrates on the GSU transformers in the BES, and as a result failure statistics on the even larger population of autotransformers in the BES is unknown. Therefore this analysis could be greatly understating the trend line of transformer failures and prior geomagnetic storms.

The NERC GMD Standards development process has not taken into consideration past failure events. In many instances various NERC reports have actually emphasized that only one transformer of a no-longer used 1970 design has failed due to GIC. There have even been well-documented instances where NERC refused to collect specific failure data reports and GIC measurements that are known to exist. Hence the ability of NERC to appropriately design forward looking standards in this vital area should be suspect.

Section 2. – Analysis of Autotransformer Tertiary Winding Vulnerability

The NERC process for determining autotransformer vulnerability has not taken into consideration the highly vulnerable tertiary windings that are common on most autotransformers in the US BES. Transformer manufacturers have also not provided public inputs on this topic area either. In a recent NERC GMD Task Force meeting, a presentation was provided on the GIC withstand estimates for a 765/345/34.5kV 750 MVA autotransformer. This presentation made no mention of the analysis of the tertiary winding heating vulnerability issues, rather it draws conclusions on winding vulnerability only from assessing the main windings of the autotransformer.

There are a number of reasons that the Tertiary winding vulnerability is more critical on autotransformers. These windings are typically much lower MVA rated than main windings. From available data, the MVA Ratings of Tertiary Windings can be as low as 4% of Main Winding MVA Rating. The tertiary winding is Delta Connected. In the case of single phase transformers, the delta connected tertiary winding will allow the flow of all Triplen (or Zero Sequence) Harmonics that are present due to GIC on the Main Windings. These Zero Sequence Currents will be present and flowing in the delta windings even when the Tertiary is unloaded. Because of this, Loading Guides for Reducing Load with Elevated GIC will be entirely ineffective, as the Tertiary Winding is already unloaded in most cases and load changes on the Main windings will not alter the production of Zero Sequence Harmonics due to GIC. Further, because the Tertiary winding is of significantly reduced MVA compared to the main winding, there is very limited capability to absorb the transformed zero sequence harmonics in the tertiary compared to the main windings. The only way to protect this vulnerable winding is taking the transformer out of service or mitigation actions to block/reduce GIC flows in the main windings.

In the recent NERC GMD TF presentation (March 2014), a transformer manufacturer assessed a 765kV transformer for a transmission owner/operator for various levels of GIC flow. Figure 2-1 provides a summary of the Harmonics due to these various levels of GIC. As shown in this graphic summary, it is estimated that there will be substantial Zero Sequence Harmonics produced at the 3rd, 6th, and 9th harmonic frequencies.

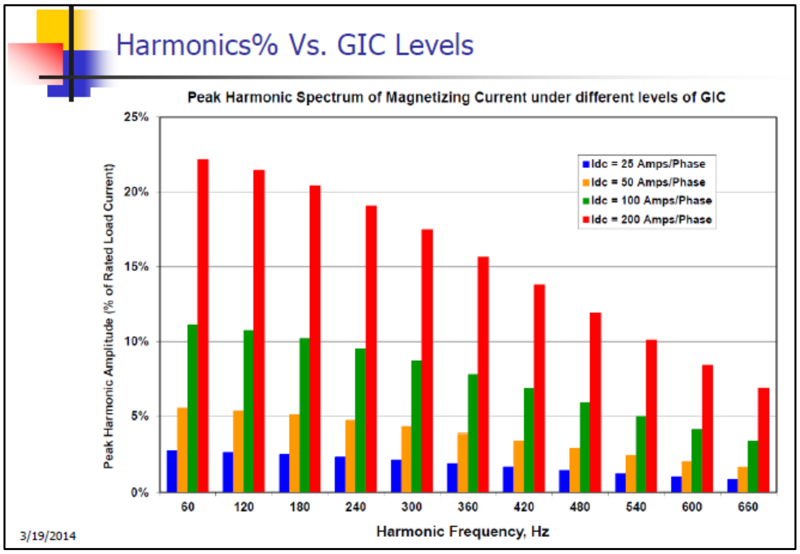

Figure 2-1 – Transformer Manufacturer Estimates of Harmonic Currents in 765kV Transformer Main Windings due to GIC

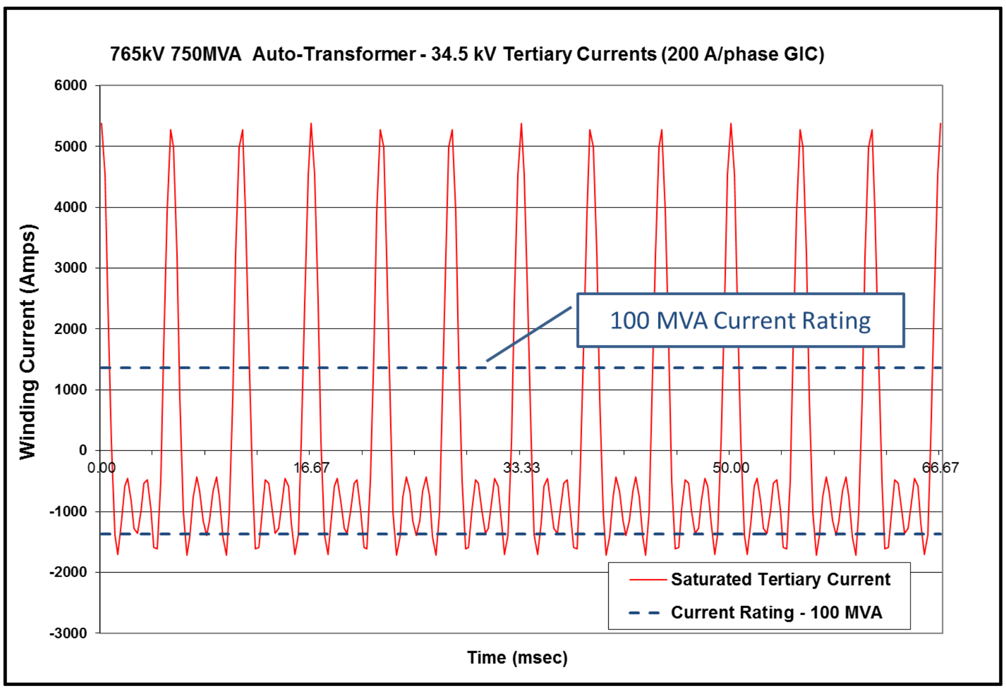

Figure 2-2 – Tertiary Winding AC Current and 100MVA Current Rating Limits for 200 A/phase GIC in Main Windings.

In the case of this particular transformer, the Main Winding has an MVA Rating of 750MVA, while the Tertiary Winding is 100MVA (i.e a 13.3% ratio, noting that ratios for even larger EHV transformers will typically be lower than 13%). In this particular case and for the 200 Amps/phase GIC level, the estimated Tertiary Winding AC Current Waveform using the harmonics from Figure 2-1 for this transformer is shown in Figure 2-2.

As this example illustrates, the waveform greatly exceeds the continuous current rating by as much as a factor of ~4. While these overloads would not be tolerable for a 60 Hz current, the reality of this case is that this example waveform consists of large components of 3rd, 6th, & 9th harmonics. Because of the harmonics this will greatly increase the winding losses (compared to same current at 60Hz), and winding heating from eddy currents and other stray loss factors. Tertiary Winding Losses can be calculated using the standard guidelines of ANSI/IEEE C57.18.10. Figure 2-3 provides a plot of the increase in Tertiary winding losses for increasing GIC levels using the inputs provided by the transformer manufacturer in Figure 2-1. As this plot illustrates, this tertiary winding will be subjected to enormous loss increases for increasing GIC. The losses will be highly concentrated in this winding accounting for more than 80% of all transformer losses. This high loss and heating concentration will greatly accelerate tertiary winding temperature increases as the rate of temperature rise is not a set "time constant", but rather is a response to the excessively high rate of energy input in these windings compared to any other location within the transformer. This is a process which can rapidly cause winding/insulation system failures. The slower time delays assumed in other locations in the transformer main windings will not be accurate for this location.

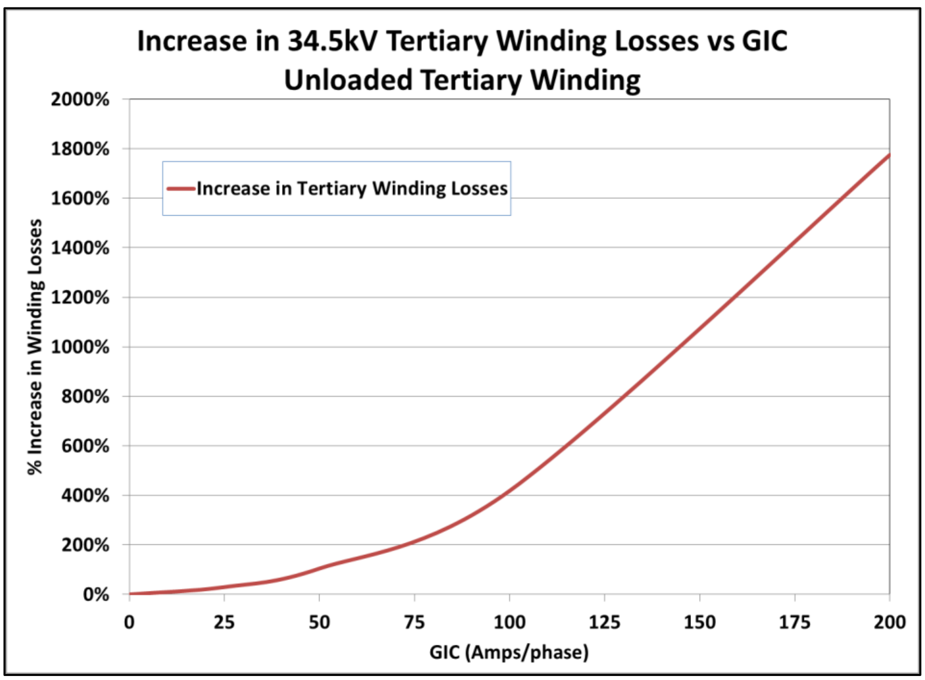

Figure 2-3 – Increase in 765kV Autotransformer Tertiary Winding Losses vs GIC levels.

In addition to losses, the same ANSI/IEEE standard can be utilized to estimate the winding hot spot levels that would occur for these GIC/harmonic exposure conditions in the tertiary windings. Figure 2-4 provides a summary of these temperature increases and also depicts the GIC and temperature limits that would normally be applied. As this analysis illustrates, the limitations of winding temperatures will be reached in the tertiary windings for very low levels of GIC flow. In the Presentation to NERC, the manufacturer had concluded that this transformer could withstand much higher GIC levels, but had based this only upon examinations of the main windings and had not included these smaller MVA tertiary windings. The transmission operator noted that these particular tertiary winding MVA ratings were relatively large in their network compared to other transformers that would have tertiary windings with lower MVA ratings. This suggests that even more severe limitations would exist in these other network transformers. As noted, this 100 MVA tertiary was rated at 13.3% of the Main Winding MVA, to examine the impact on lower rated Tertiary windings, the same set of calculations were carried out for 10% (75 MVA) and 7% (50 MVA) tertiary windings. These results are presented in Figure 2-5.

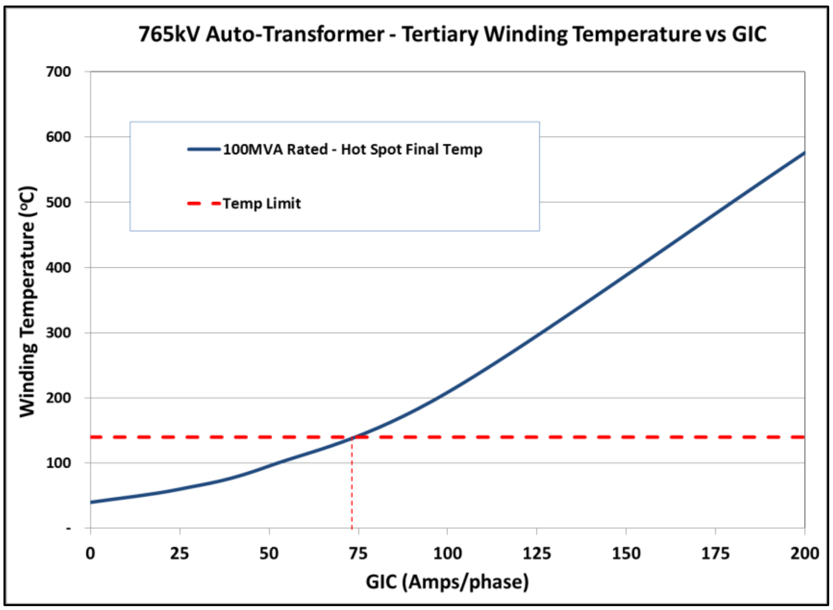

Figure 2-4 – Tertiary Winding Temperature vs GIC for 765kV Autotransformer.

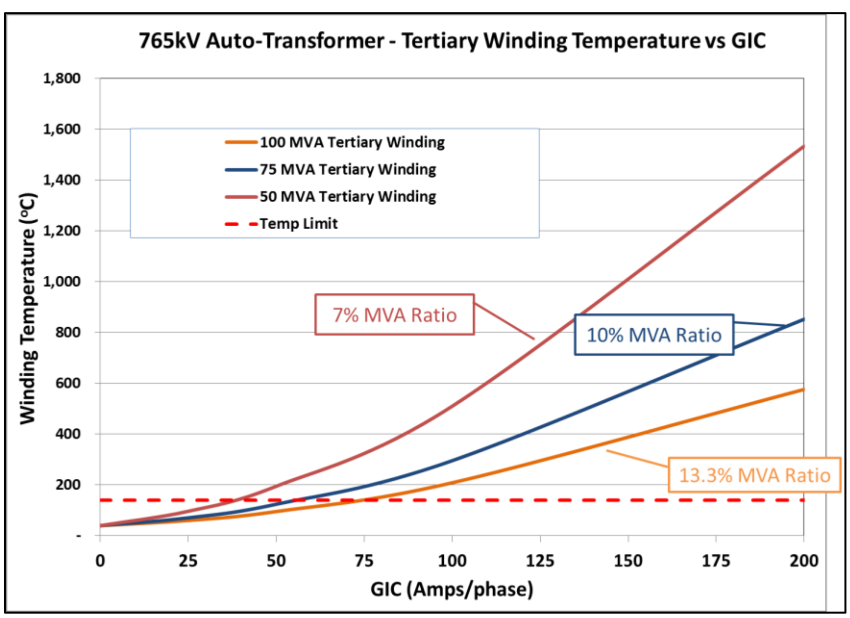

Figure 2-5 – Increase in Tertiary Winding Temperature vs GIC for 13.3%, 10% and 7% Rated Tertiary Windings

As expected, in Figure 2-5, a decreasing Tertiary MVA rating results in a proportionately higher winding temperature risk for the same level of GIC. The main windings and GIC flows of the main windings are what determine the harmonics produced by saturation. The zero sequence harmonics in the tertiary will be “fixed or controlled” based on the voltage turns ratio of the main winding to tertiary. The MVA rating of the tertiary is not a limiting factor for this transformation, but as the MVA rating of the tertiary decreases, the onset of overload and resulting over-temperature conditions will be proportionately reduced. As previously noted, the general trend in the industry is to specify a smaller % MVA rating for the tertiary winding as the MVA rating of the EHV transformer increases. In some cases the tertiary rating can be below 5% of the main winding. Unfortunately it is also these large MVA EHV autotransformers that are most likely to be exposed to high GIC flows in the network. This design trend therefore acts to heighten the risk of damage to these transformers for severe geomagnetic storm events.

The vulnerability of tertiary windings in autotransformers has not been specifically examined by any manufacturer in the course of the NERC GMD investigations. This oversight of a key vulnerability raises legitimate concerns about the adequacy of proposed NERC draft standards. The draft standards also do not comprehend other failure mechanisms which other research or experiential data indicate. There are a large number of other unexamined issues that have not been resolved. These include the role of increased vibrations caused by GIC saturation that can lead to premature failures. Data from examinations of transformer failures suggest connections in vibrations with various transformer subsystems such as core and coil clamping and with premature failures in EHV bushings. There are also failure pathologies with connected subsystems such as rigid isobus structures, internal transformer connections, other connected protection and monitoring systems. There are concerns of increased partial discharge levels that are measured with GIC caused half-cycle saturation and the pathways of deleterious impacts this could have upon transformer structures such as winding and core steels even at very low but long duration GIC exposure levels.

Section 1. GMD Standard Regarding Field Scaling- Southerly Locations

As NERC has noted in their description of the proposed GMD Standard, they have selected a reference waveform scaled from the Ottawa magnetometer data from the March 13-14, 1989 storm. The most convenient way to approximately estimate the geo-electric field and GIC in power grids is by comparing the rate of change (dB/dt) of the reference geomagnetic field. Figure 1-1 provides a summary of the rate of change of the horizontal component of this reference field located at the 60° geomagnetic latitude.

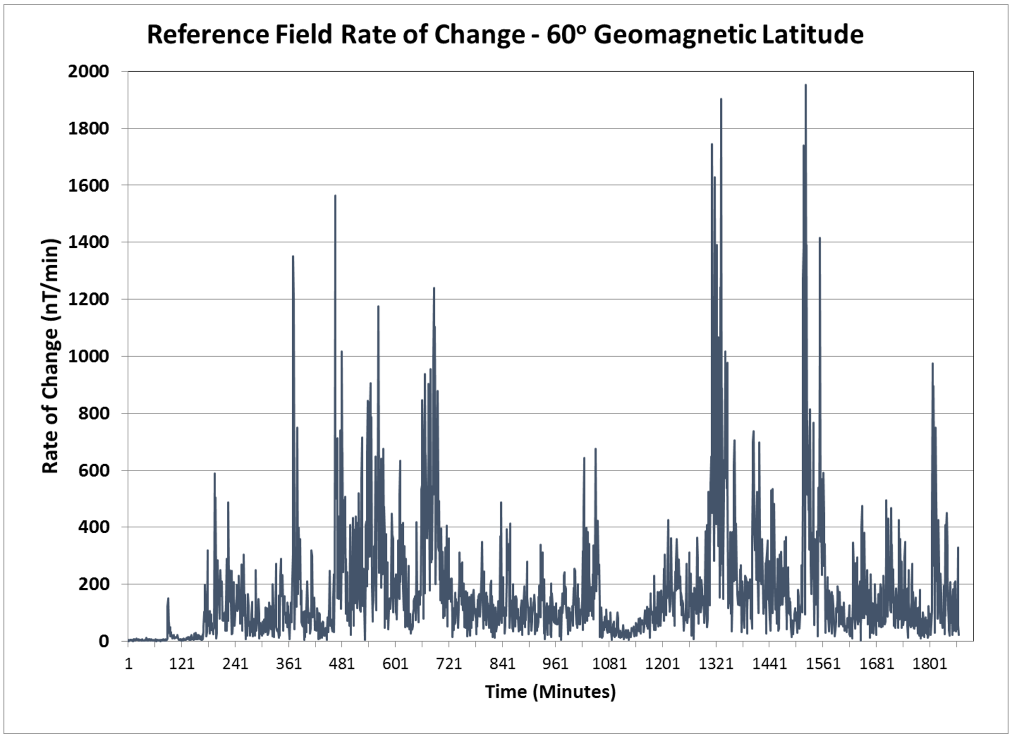

Figure 1-1 – dBh/dt (nT/min) of NERC Reference Geomagnetic Field

In the field scaling approach that NERC has recommended in their standard, they propose to use a formula to scale from the reference field defined at 60° geomagnetic latitude to locations further south in the US. Figure 1-2 from the NERC standard overview provides the basic scaling formula. In this formula the factor alpha provides a latitude scaling factor that can be applied to the Ottawa waveform to determine scaling at all more southerly locations that can be applied. Figure 1-3 provides several example locations on what the scaling factors would be, in this figure, they note that for a location such as New York would be determined by scaling the reference field to only 30%. Further at a more southerly location like New Orleans, they would scale the reference field to only 10% levels.

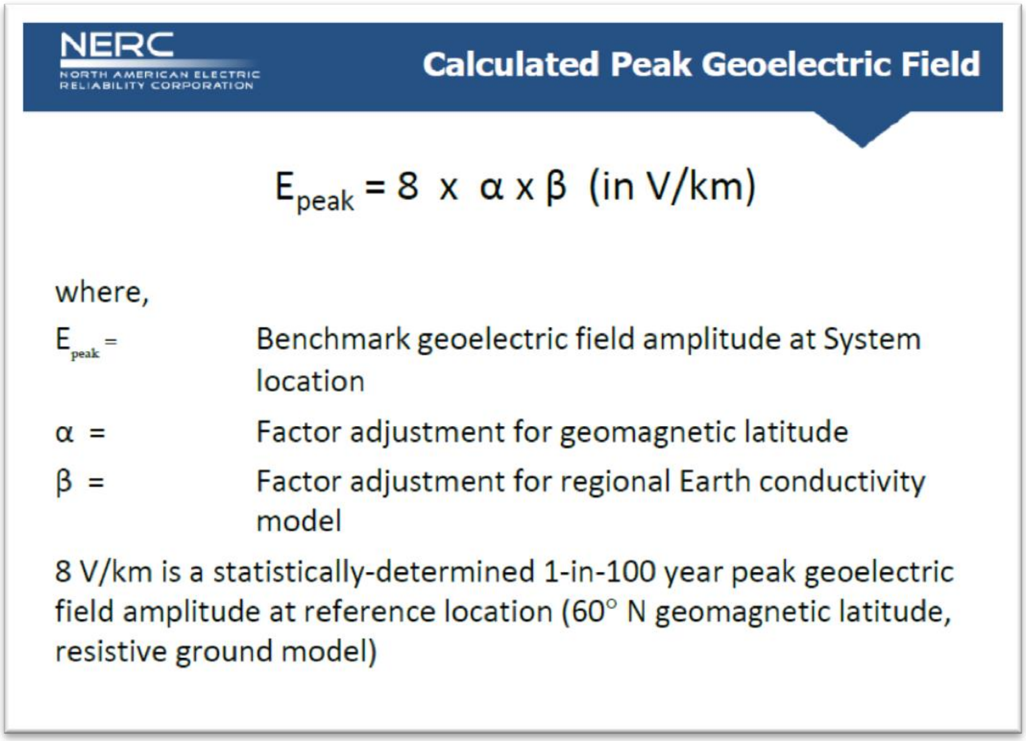

Figure 1-2 - NERC GMD Standard Location Scaling Formula

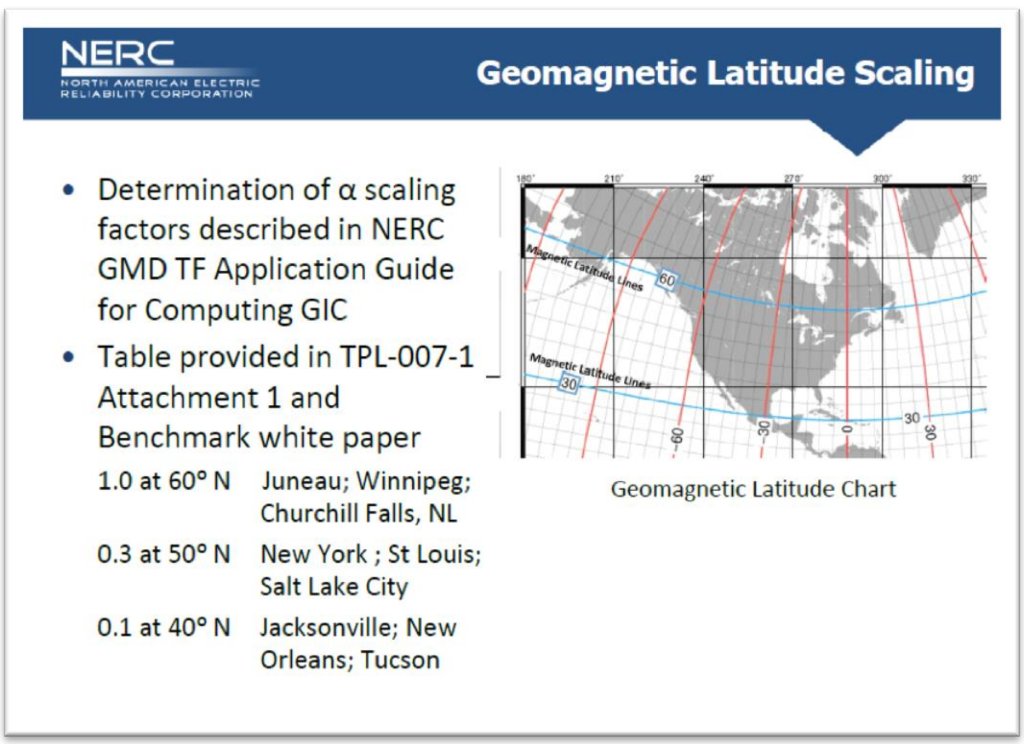

Figure1-3 – Example of 30% Scaling for NY and 10% Scaling for New Orleans

This formula approach can be readily compared to actual observations to examine if the formula provides a correct scaling factor for a 1-in-100 year scenario. In this case, we will just illustrate the scaling as applied to the reference field of dBh/dt field of Figure 1-1. To further simplify, the peak dBh/dt of this reference field was ~1950 nT/min.

In the case of latitudes at New Orleans, the peak dBh/dt would be scaled to 10% of this ~1950 nT/min peak, resulting in a peak dBh/dt of the scaled reference field of ~195 nT/min. Figure 1-4 provides a plot of the dBh/dt that was actually observed in the New Orleans region from the nearby Bay St. Louis magnetic observatory during the March 13-14, 1989 storm. As shown in this storm data, the BSL observatory experienced a peak dBh/dt of 460 nT/min. As a result, the proposed NERC scaled reference waveform would understate what was actually observed in the region by over a factor of two (2).

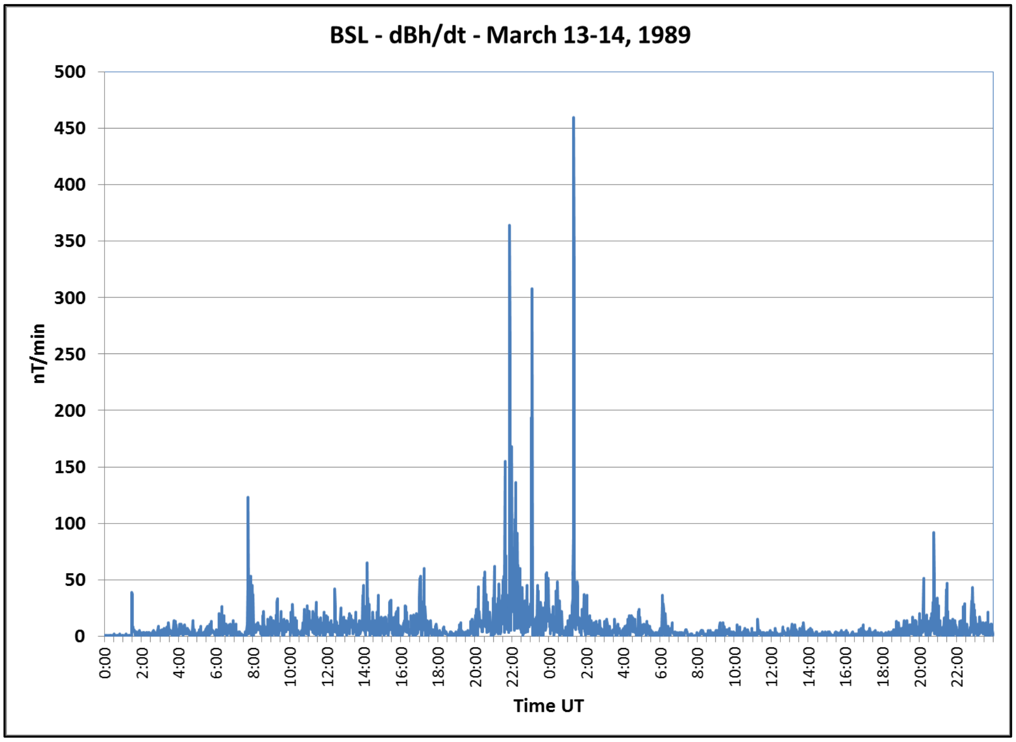

Figure 1-4 - Actual BSL Observation on March 13-14, 1989 for New Orleans location

As this comparison illustrates, the NERC Scaling formula which adjusts the reference waveform to more southerly locations is not correct for this storm and should be called into question for a much larger storm of the 1-in-100 year class. Rather than providing "conservative" characterizations of the disturbance conditions, the NERC scaled waveform formula produces unrealistically optimistic waveform intensities.

Section 2. Benchmark GMD Event – 1-in-100 Year Amplitude

From the NERC GMD Standard summary, Figure 2-1 notes that they have derived a geomagnetic referenvce field based on the March 13-14, 1989 storm. This reference field is scaled to meet their definition of a “1-in-100 year amplitude”. Further as noted in Figure 2-2, they have determined that the Ottawa observatory waveforms are best suited to represent this 1-in-100 year field waveshape.

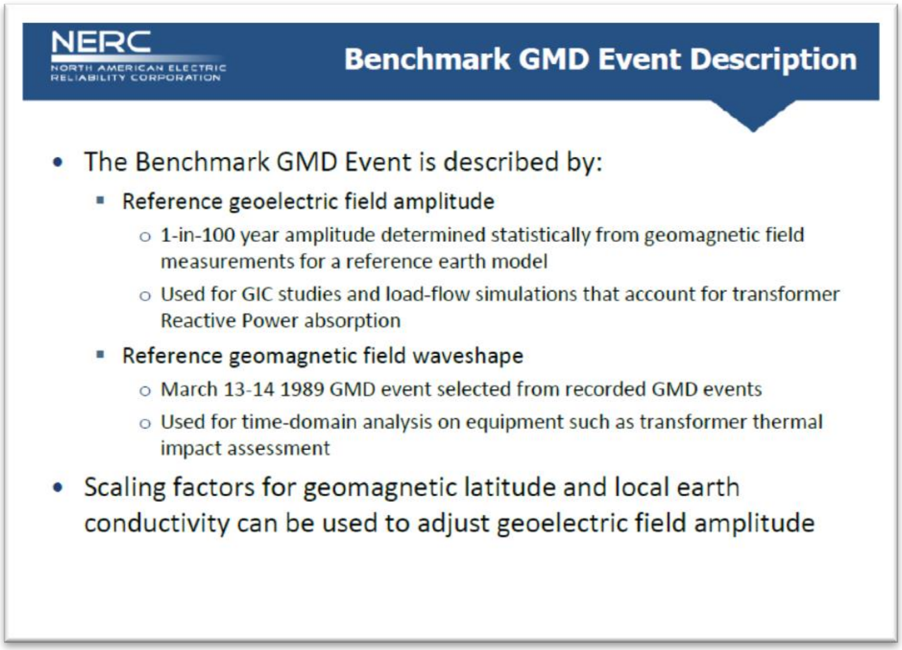

Figure 2-5 – From NERC GMD Standard Summary, March 13-14, 1989 storm as basis for GMD Standard

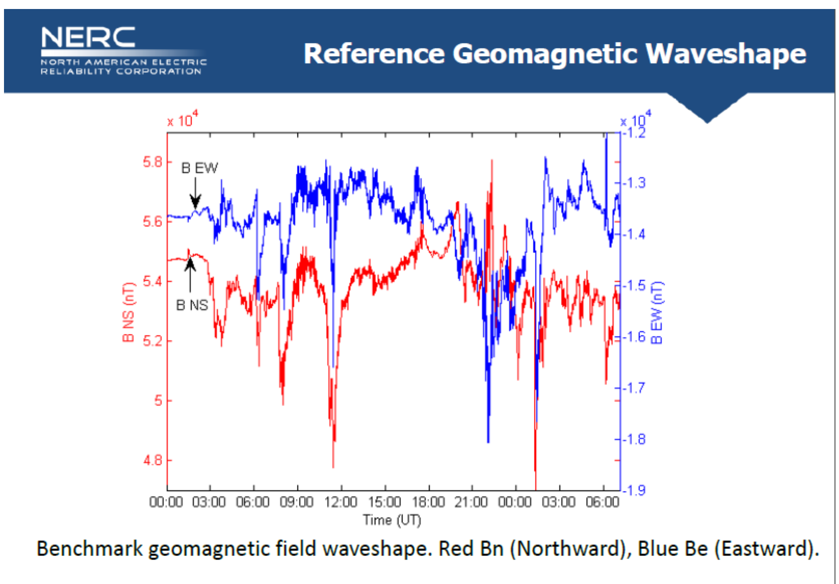

Figure 2-6 – Ottawa selected as Benchmark geomagnetic storm waveshape

The reference field is defined as being located at 60^{o} geomagnetic latitude. Figure 2-3 provides a summary of the rate of change of the horizontal field of the reference waveform. As this figure shows, the dBh/dt reached a peak of ~1950 nT/min for this location.

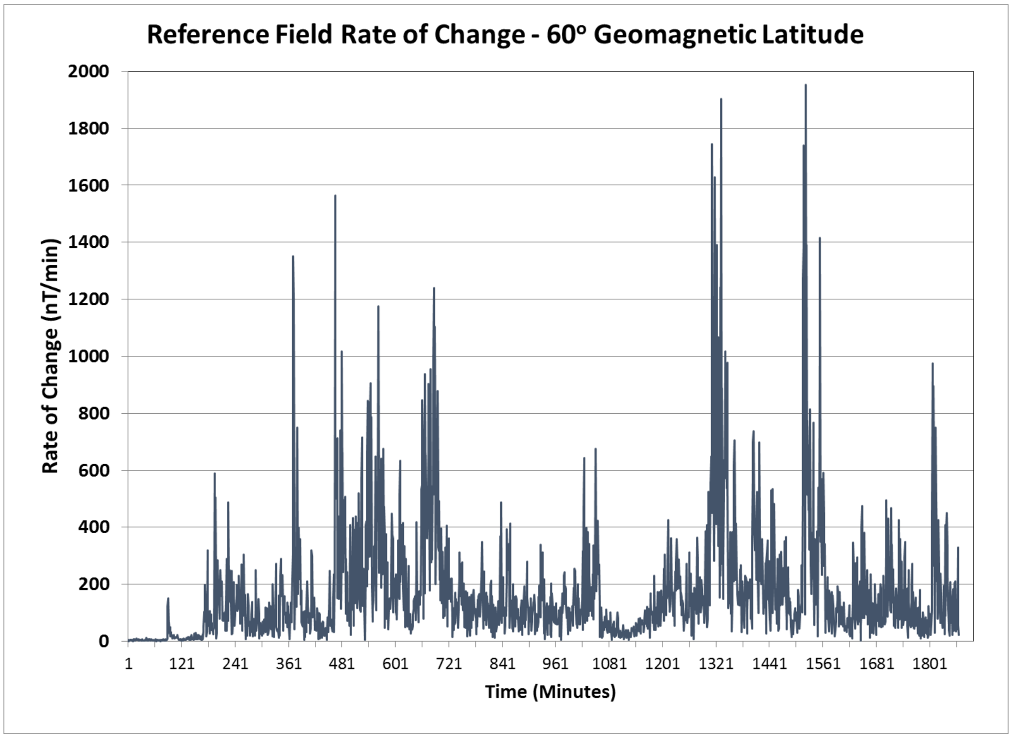

Figure 2-7 – Reference Field dBh/dt

The Ottawa observatory is located in southern Ontario Canada at the geographic latitude of 45.04°, but with a geomagnetic latitude of 56.05°. The Draft NERC Standard would reduce the above "Reference Field" to 60% for a geomagnetic latitude location of 56°. Using this scaling guide, the peak dBh/dt would be ~1170 nT/min for peak threat environment levels for electric grid infrastructures located at this latitude.

However the data available from several contemporary storms indicates that there are serious problems with these NERC threat environment conclusions. When considering geomagnetic storm climatology in North America, it is important to have a world view of the situation as well. Since a disturbance at a 50° to 56° geomagnetic latitude in Europe or any other world location would have an equal probability of also occurring in North America for future large storms. Figure 2-4 illustrates this principle for an example at 50° across the northern hemisphere. In the case of the March 13-14, 1989 storm, the largest dBh/dt was actually observed at the Brofelde observatory in Denmark (geographic latitude of 55.6° and geomagnetic latitude of 55.3°), which has a geomagnetic latitude even further southward than either Ottawa. Figure 2-5 provides a plot of the observed dBh/dt at the Brofelde magnetic observatory on March 13-14, 1989. At time 21:44UT, the peak dBh/dt at Brofelde reached 1968 nT/min, a level which is ~1.7 times larger than the proposed ~1170nT/min for this latitude for the NERC GMD Standard. The occurrence of large substorm events with a dBh/dt of 1968 nT/min at 21:44UT located at Brofelde are a consequence primarily of the randomness of the timing of the event not geographic location. Had this substorm event occurred approximately 7 hours later, this large impulsive disturbance would have been positioned over North America and arguably caused much higher geo-electric fields, GIC's and impacts to the North American power grid than envisioned by the proposed GMD standard. The substorm randomness is related to randomness of the arrival timing of the CME and the interactions in the magnetosphere that trigger these violent events. Therefore, excluding large dBh/dt events that are not over North America cannot be defensed from a point of the scientific understanding storm interactions.

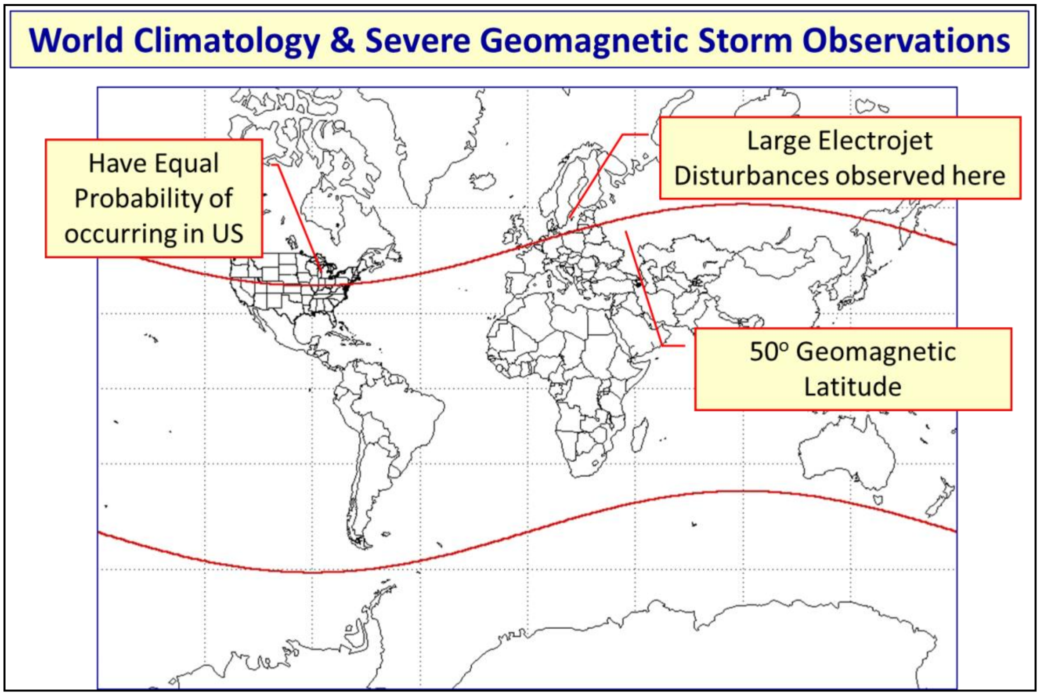

Figure 2-8 – Geomagnetic Storm Extreme Observations as a function of geomagnetic latitude worldwide

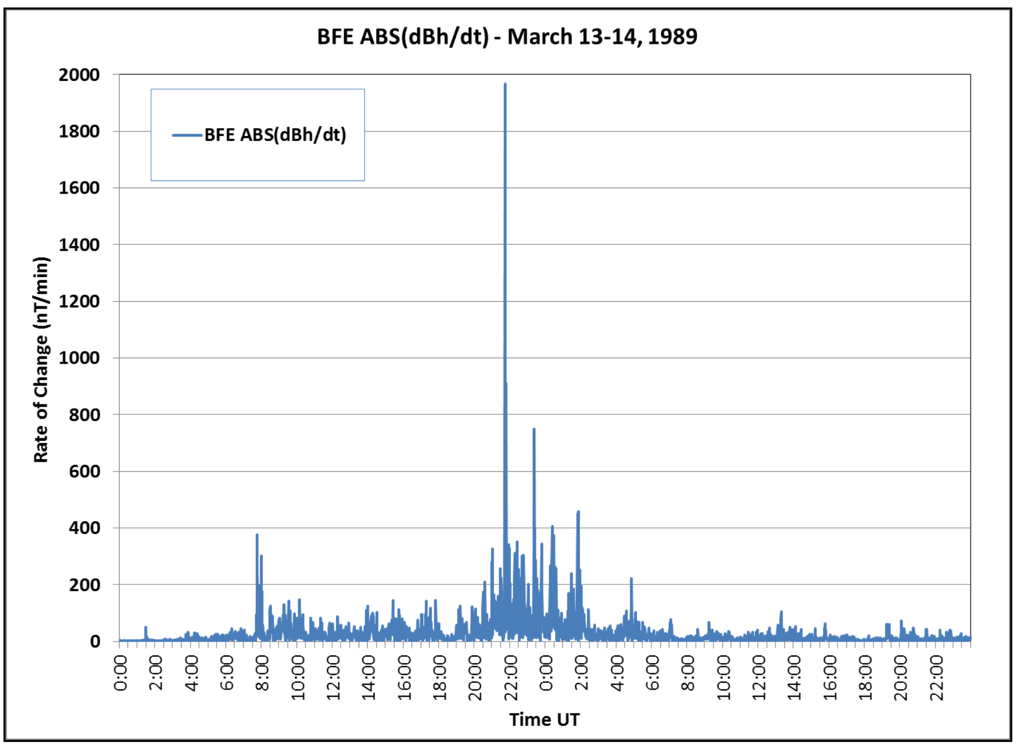

Figure 2-9 - Brofelde dBh/dt on March 13-14, 1989

In addition to the Brofelde observations from the March 13-14, 1989 storm, there are other well-known instances of large impulsive disturbances at latitudes of concern for the North American power grid. For example one of the largest dBh/dt observations occurred in the same region during the July 13-14, 1982 storm. Figure 2-6 provides a plot of the observed dBh/dt at the LOVO observatory near Stockholm. At this location (geomagnetic Latitude of 57.7° which is located at similar geomagnetic latitude of Ottawa), the dBh/dt impulsive disturbance reached an intensity of 2688 nT/min. This level is ~2.3 times larger than the proposed GMD standard waveform.

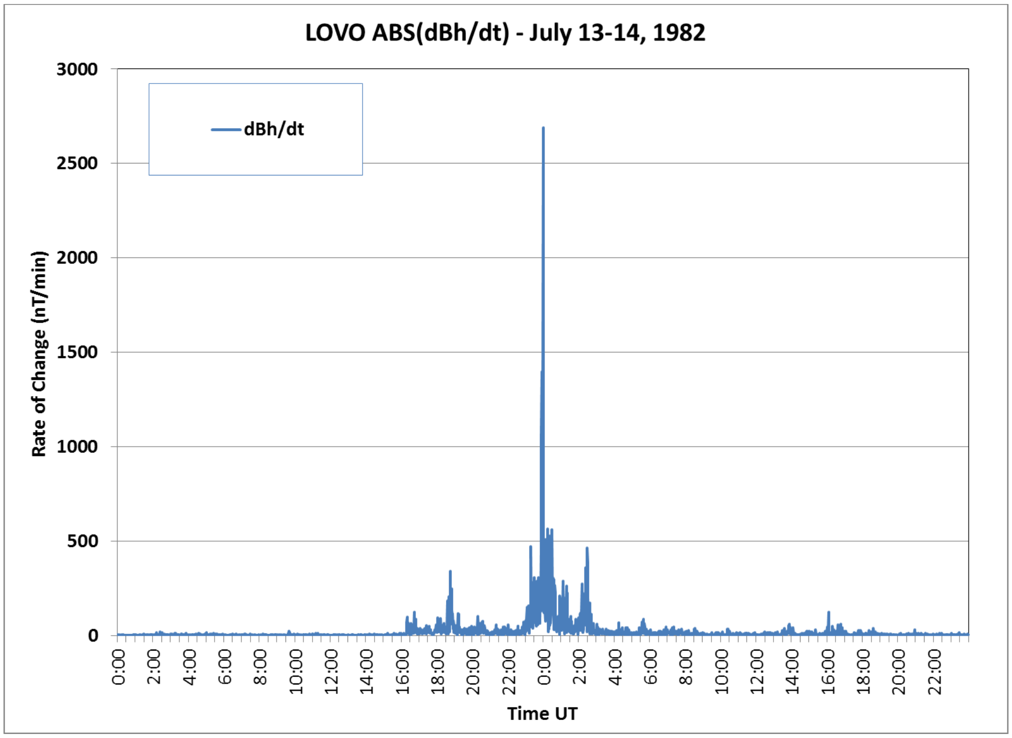

Figure 2-10 - LOVO dBh/dt on July 13-14, 1982

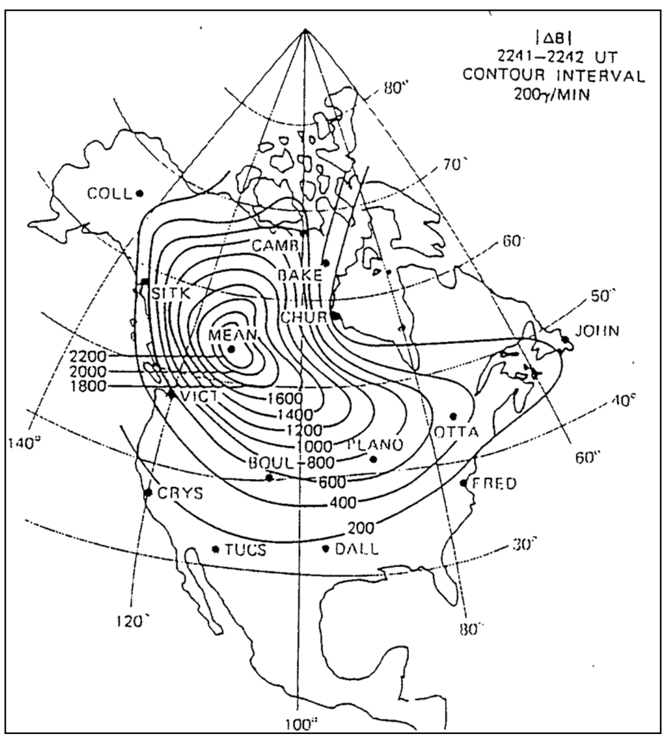

Figure 2-11 – Observed 2200 nT/min impulsive disturbance over North America on August 4, 1972 (from Anderson, Lanzerotti, et. al.).

Historically, it is known that large impulsive events have occurred over North America. Figure 2-7 provides a map of the morphology of a large ~2370 nT/min event at 22:41UT on August 4, 1972 which was positioned over the western half of North America. This is a level that is over 20% higher than the proposed NERC reference field rate of change intensity at 60^{o} geomagnetic latitude.

These are three specific events that have occurred over just the past ~40 years, this suggests that a 1-in-100 year impulsive disturbance could be even higher in intensity. Various researchers have examined available data from storm events on May 1921 and Sept 1859 and suggest that impulsive disturbance intensity levels could be as much as ~5000 nT/min. These would be intensity levels over 10 times larger than presently proposed for the NERC GMD Standard waveform. This analysis and overview calls into question the appropriateness of the NERC GMD waveform and whether it can be classified as a conservative threat environment or a 1-in-100 year threat environment.

Section 3. Benchmark GMD Event – Geographic Footprint

From the NERC GMD Standard summary, Figure 3-1 notes that NERC has determined that impulsive disturbances during benchmark storms will have relatively small regions (~100km). We question the extent that this position is reliable or can be relied upon in standard setting based upon known large storms events over just the past few decades. Such determinations of small spatial averaging would not follow from analysis of the storm large impulsive disturbance environments itself, nor are we aware of any comprehensive assessment of US ground conductivity behaviors that would support such conclusions at this time.

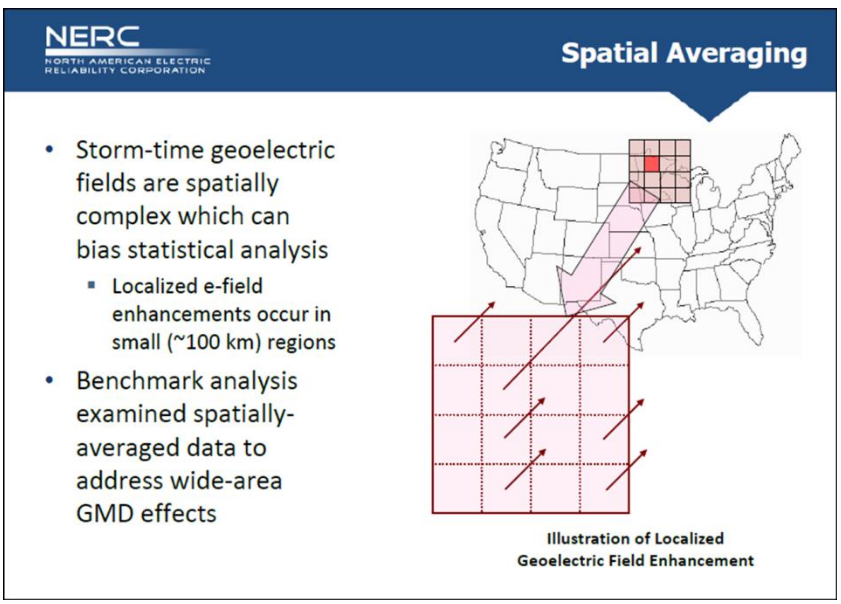

Figure 3-12 – From NERC GMD Standard Summary, Spatial averaging

As was previously noted in Figure 2-7 on August 4, 1972, the geographic footprint of a large impulsive disturbance can be enormous. Data on the geographic extent of these large dB/dt disturbances can also be extracted from the March 13-14, 1989 and July 13-14, 1982 events also discussed in Section 2 of these comments. In the case of the March 1989 storm, the large dBh/dt disturbance of 1968 nT/min at 21:44UT at Brofelde was also accompanied by the simultaneous observation of a dBh/dt intensity at Eskdalemuir observatory in Scotland of 978 nT/min at 21:44 and 1092 nT/min at 21:45UT. This observatory is ~935 km east of Brofelde and the closest observatory in that direction from Brofelde. The simultaneous observations of large impulsive disturbances at both locations suggest a single upper atmospheric current system in an east-west direction that is the driver of both observations.

In the case of the July 13-14, 1982 impulsive event, a north-south chain of magnetometers extending from Sodankyla in Northern Finland, to Lovo in Central Sweden to Brofelde in Denmark all simultaneously observed at 23:59-0:00 UT large impulsive disturbances. As previously noted in Section 2, the intensity observed at Lovo was 2688 nT/min. To the north and east at Sodankyla, the intensity reached 1905 nT/min, while at the southerly location of Brofelde, the dB/dt intensity was 1005 nT/min. For this storm there are only a limited number of observatories in operation, yet this small sample confirms a large geographic laydown. The distance from Sodankyla to Lovo to Brofelde spans an East-to-West coverage of ~600 km and a North-to-South coverage of ~1300 km. Even this limited example has a coverage area ~80 times larger than what is recommended in the NERC draft standard.

Respectfully Submitted by:

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www.DeltaStar.com

May 21, 2014

N.E.R.C.

Re: Mobile Electrical Recovery Systems for G.I.C.
Delta Star, Inc.

Dear Sirs:

INTRODUCTION:

Our Company, Delta Star, Inc. was originally founded in 1908 in Chicago Illinois. In the 1950's we began manufacturing medium power transformers at our two current locations, San Carlos, California, and Lynchburg, Virginia. In 1988 Delta Star, Inc. became an ESOP and we currently employee approximately 600 persons.

In 1976 we produced our first Mobile Substation and we are virtually the sole manufacturer of mobiles in the United States. We have manufactured more mobiles than the entire world and are supplying mobiles to nearly every major utility in the United States and Canada. For example, American Electric Power (AEP) has purchased over 120 Mobile Substations over the years and we have also supplied mobiles to many investor owned utilities (I.O.U's), electric coops, and many major cities.

The following briefly explains the ways that Mobile Substations have been used and how they may be used in the future for GIC. Also, given the fact that F.E.R.C. will soon enter into rulemaking for other substation security issues we have included a summary of additional uses for a mobile.

USAGE:

I. Initially, mobile functions were confined to three uses:

1) the failure of a substation, and
2) the regular maintenance of a substation, and
3) the ability to distribute electricity at a commercial or residential building site prior to the completion of a substation. (see Governmental Study for the utilization of mobile substation by Oak Ridge Laboratories)

Mobile for GIC:

GIC's (Geomagnetically Induced Current). These solar flare events are mostly unpredictable. If a Mobile Substation is used only in emergency situations, at idle they are not connected to the grid, and thusly not affected by GIC's.

Mobiles for Additional Emergency Usage:

1) Terrorism: As we have done in the past, a mobile can be manufactured to be enclosed in metal. Having no visual identification as a mobile, an additional layer of Kevlar like material can be shaped inside the mobiles.

2) EMP's: At their extreme (high attitude nuclear explosions, causing EMP's to travel at the speed of light, within the line of sight) its effect of "frying electronics" results in a catastrophic event reducing civilization to a pre-colonial era society. Mobile Substations can be manufactured in two different ways. When done in an electro-mechanical design the mobile is immune to EMP's.

3) Natural Disasters: When used in coordinated planning the mobile substation can be utilized as a method to create a reverse cascading electrification to a large geographical area, while providing the ability to prioritize segments requiring electricity at an earlier stage, e.g., communications, military, hospitals, financial services, etc.

II. Conclusion: Having survived acts of terrorism, GIC's, EMP's, and natural disasters, the question becomes of what use is a mobile if the rest of the electrical infrastructure is "fried" or totally disabled?

The answer has already been partially accomplished. After the 2003 blackout on the east coast, a navy nuclear submarine was used to start up a power station in New York City, by cabling the nuclear engine directly to the power station.

In the scenarios described herein, the nuclear cable from a nuclear ship would run to a step-up transformer and then to a Mobile Substation to distribute the power directly to the prioritized site.

We have enclosed materials you might find helpful from our perspective. Myself, our vice presidents, engineering experts, and planners, would appreciate the opportunity to expound on any of these matters and respond to any questions you have.

Sincerely,

Ivan H. Tepper
President & CEO

Enclosures

EIS Council Comments on Benchmark GMD Event

For NERC GMD Task Force Consideration

Submitted on May 21, 2014

Introduction

The Electric Infrastructure Security Council's mission is to work in partnership with government and corporate stakeholders to host national and international education, planning and communication initiatives to help improve infrastructure protection against electromagnetic threats (e-threats) and other hazards. E-threats include naturally occurring geomagnetic disturbances (GMD), high-altitude electromagnetic pulses (HEMP) from nuclear weapons, and non-nuclear EMP from intentional electromagnetic interference (IEMI) devices.

In working to achieve these goals, EIS Council is open to all approaches, but feels that industry-driven standards, as represented by the NERC process, are generally preferable to government regulation. That said, government regulation has proven necessary in instances (of all kinds) when a given private sector industry does not self-regulate to levels of safety or security acceptable to the public. EIS Council is concerned that the new proposed GMD benchmark event represents an estimate that is too optimistic, and would invite further regulatory scrutiny of the electric power industry.

The proposed benchmark GMD event represents a departure from previous GMDTF discussions, where the development of the "100-year" benchmark GMD event appeared to be coming to a consensus, based upon statistical projections of recorded smaller GMD events to 100-year storm levels. These levels of 10 – 50 V/km, with the average found to be 20 V/km, were also in agreement with what were thought to be the storm intensity levels of the 1921 Railroad Storm, which, along with the 1859 Carrington Event, were typically thought to be the scale of events for which the NERC GMDTF was formed to consider.

The new approach described in April 14, 2014 Draft contains several key features that EIS Council does not consider to yet have enough scientific rigor to be supported, and would therefore recommend that a more conservative or "pessimistic" approach should be used to ensure proper engineering safety margins for electric grid resilience under GMD conditions. These are:

1. The introduction of a new "spatial averaging" technique, which has the effect of lowing the benchmark field strengths of concern from 20 V/km to 8 V/km;

2. A lack of validation of this new model, demonstrating that it is in line with prior observed geoelectric field values;

3. The use of the 1989 Quebec GMD event as the benchmark reference storm, rather than a larger known storm such as the 1921 Railroad storm;

4. The use of 60 degrees geomagnetic latitude as the storm center; and

5. The use of geomagnetic latitude scaling factors to calculate expected storm intensities south of 60 degrees.

Spatial Averaging and Model Validation

The introduction of the spatial averaging technique is a novel introduction to discussions of the GMDTF. While the concept could prove to have validity, the abrupt change to a new methodology at this time is not fully understood by the GMDTF membership, nor has it yet had any peer review by the larger space weather scientific community. In order to ensure confidence that this is a proper approach, it is necessary that this approach be validated with available data via the standard peer-review process.

Prior findings of the GMDTF of a 20 V/km peak field values were shown to be in line with prior benchmark storms such as the 1921 Railroad storm, for which there is very good magnetometer data across the United States and Canada. Even for the 1989 Quebec Storm, on which this new benchmark is supposed to be based, it is not clear whether the new spatial averaging technique has been demonstrated to be in line with the known magnetometer data. This would seem to be a fairly straightforward validation of this new model, but is currently lacking in the description of the new approach.

The spatial averaging method also appears to be at odds with standard engineering safety margin design approaches. As an example, if the maximum load for a bridge is 20 tons, but the average load is 8 tons, a bridge is designed to hold at least 20 tons, or more typically 40 tons, a factor of two safety margin over the reasonably expected maximum load. It is recommended that the screening criteria be increased to encompass the maximum credible storm event, rather than an average, in line with typically accepted best practices for engineering design.

The description of the method does describe that within the expected spatially-averaged GMD event of 8 V/km, that smaller, moving “hot spots” of 20 V/km are expected. It therefore seems prudent for electric power companies to analyze the expected resilience of their system against a 20 V/km geoelectric field, as any given company could find themselves within such a “hot spot” during a GMD event.

One further point to consider is that, while the GMDTF scope does not at present include EMP, the unclassified IEC standard for the geoelectric fields associated with EMP E3 is 40 V/km. Should the scope of the GMDTF or FERC order 779 ever be expanded to include EMP E3, 40 V/km is the accepted international standard, something to consider when setting the benchmark event, as any given power company could find themselves subject to the maximum credible EMP E3 field.

1989 Quebec Storm as the Benchmark Event

The 1989 Quebec Storm is very well-studied event, and is a dramatic example of the impacts of GMD on power grids. The loss of power in the Province of Quebec, failure of the Salem transformer, and other grid anomalies associated with the storm are all well documented. The GMDTF was formed, and FERC Order 779 issued, to ensure grid resilience for events that will be much larger than the 1989 Quebec Storm, such as the 1921 Railroad Storm. The two figures below show a side-by-side comparison of the 1989 and 1921 storms. The geographic size, and also the latitude locations are quite striking.

The use of the 1989 Quebec Storm as the benchmark event is of concern because simply scaling the field strengths of the 1989 Storm higher (an "intensification factor" of 2.5 is used), but leaving the same geographic footprint, does not appear to be a valid approach. While the 2.5 scaling factor is described to produce local "hot spots" of 20 V/km, in agreement with earlier findings, it fails to consider the well-known GMD phenomena that the electrojets of larger storms shift southward, as can be seen in comparing the two figures. By using the geographic footprint of the 1989 storm, the new benchmark will predict geoelectric field levels that are incorrect for geomagnetic latitudes below 60 degrees, where the center of the new benchmark storm has been set.

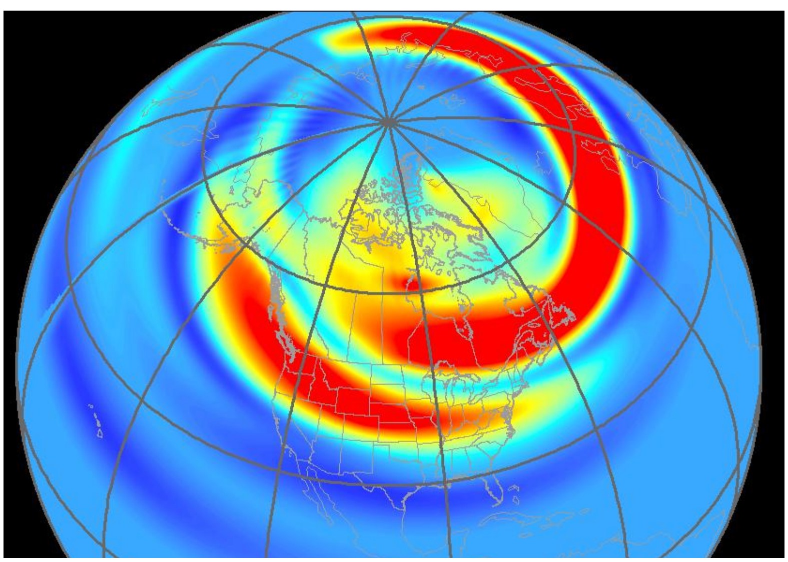

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

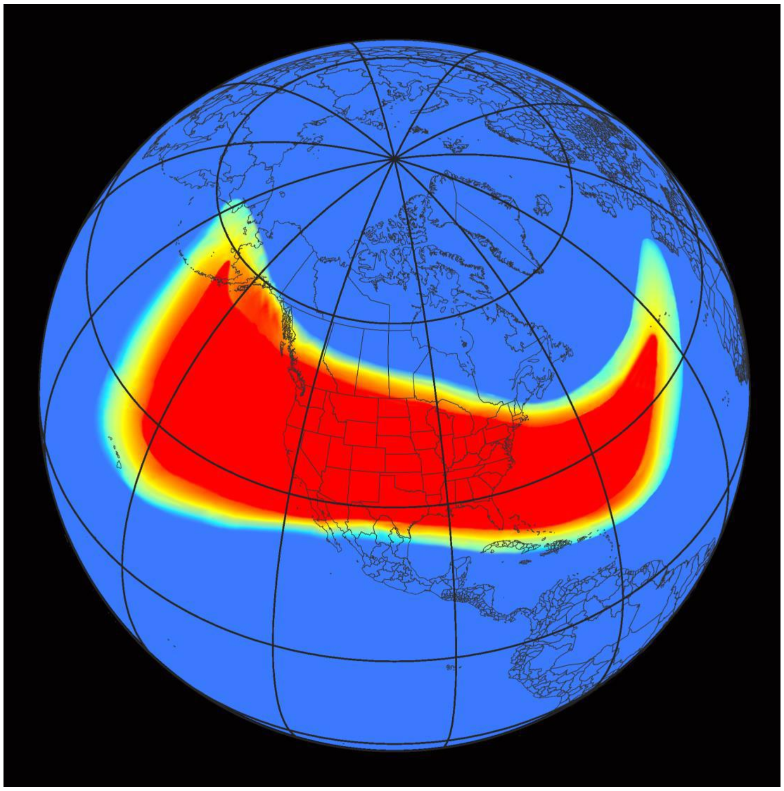

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

As the figures above show, GMD events larger than the 1989 Quebec event are expected to be larger in overall geographic laydown (continental to global in scale), and also to be centered at lower geomagnetic latitudes than the 1989 storm, due to a southward shifting of the auroral electrojet for more energetic storms. While the latitudinal scaling factor α may be correct for a storm like the 1989 Storm and centered on 60 degrees geomagnetic latitude, use of these scaling factors does not appear to be valid for GMD events where the storm will be centered at a lower latitude, and have a larger geographic footprint. While the β factor - which captures differences in geologic ground conductivity - will remain valid under all storm scenarios, the α factors would only be valid for a storm centered at 60 degrees. For example, in looking at figure 2 above, the storm is quite large, and centered at (roughly) 40 – 45 degrees North Latitude. The correct α factor for 45 degrees in this case would be 1, rather than the 0.2 value that would be correct for a storm centered at 60 degrees North Latitude. As it is not known what the center latitude of any given storm center would be, it would seem that the use of the α scaling factor is not supported.

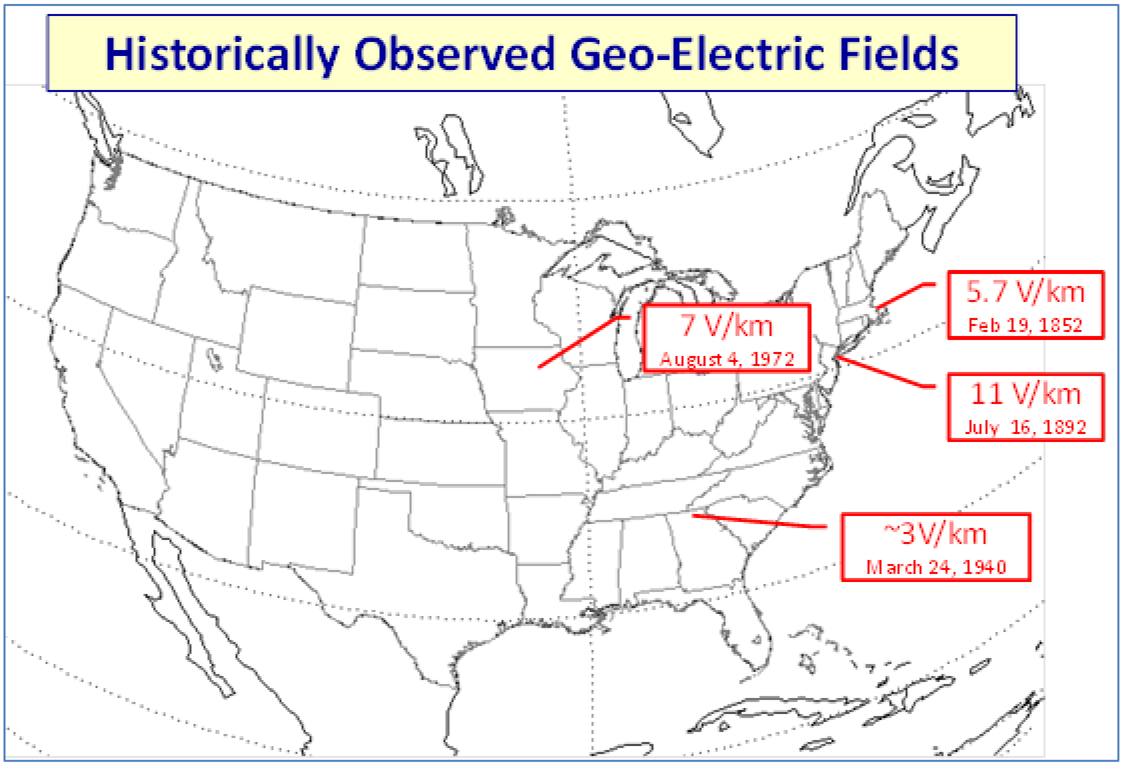

Figure 3: Historically observed geo-electric fields (Source: Storm Analysis Consultants).

Figure 3 shows a small number of measured geoelectric field intensities, indicating date and location. As can be seen, the observed values of these storm intensities (which could represent "hot spots"), are near or above 8 V/km. Given that such field intensities have been measured previously, it is recommended that a larger benchmark event be used for evaluation of system resilience for GMD events, and it must be demonstrated that the benchmark event represents a reasonable "worst-case" scenario, and captures the geoelectric field intensities of known historical storms.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there remain obvious scientific shortcomings in using a benchmark storm centered at a designated geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location, which would therefore invalidate the proposed latitudinal scaling factor. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, without the use of the scaling factor, as the benchmark event against which the individual electric power companies can analyze their system resilience.

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **May 21, 2014**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 standard(s) that require applicable entities to develop and implement Operating Procedures were filed in November, 2013.
- Stage 2 standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 standards must be filed by January 2015.

This posting is soliciting informal comments on the draft standard, TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances, being developed to address the stage 2 directives. TPL-007-1 includes requirements for Planning Coordinators, Transmission Planners, Transmission Owners, and Generation Owners with planning areas or transformers connected at 200 kV or higher.

Paragraph numbers in the following questions refer to Order No. 779.

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

Questions on Draft 1 of TPL-007-1

1. **Applicability**. The draft TPL-007-1 standard applies to Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater. The drafting team believes these are the correct functional entities to meet the directives in Order No. 779 to evaluate the effects of GICs on Bulk-Power System transformers and other equipment (P.67), consider wide-area effects and coordinate across regions (P.67), and develop plans to address potential impacts (P. 79). Justification for the 200 kV voltage threshold may be found in the whitepaper that was developed by the drafting team for the stage 1 standard, EOP-010-1 – Geomagnetic Disturbance Operations. Do you agree that these are the correct functional entities to perform the functions required in the draft standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
X☐ No

Comments: The TPL- 007 does not directly address the issue of harmonics that are generated during a GMD event which can damage generators as well as customer equipment. GMD generated harmonics can be a significant issue therefore the standard should be explicit in addressing an approach for assessing vulnerability and developing mitigation.
The standard should require both the development of vulnerability assessments and integration of these findings into the operating procedures.

2. **Technical basis**. Directives in Order No. 779 specify that the assessments required by the stage 2 standard should account for several parameters including the use of studies and simulations to evaluate the effects of GIC on the Bulk-Power System transformers (P. 59). The drafting team believes that the studies and analysis required by the standard meet the assessment parameters directed by FERC and are supported by the technical guides referenced in the standard. Do you agree that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment and are supported by the technical guidance? If you do not agree, or you recommend alternative language in these requirements or additional technical material, please provide specific suggestions in your comments.

☐ Yes
X☐ No

Comments: The standard should require both the development of vulnerability assessments and integration of these findings into the operating procedures.

3. **Benchmark GMD Event**. In Order No. 779, FERC directed that NERC specify the benchmark GMD event to be used by entities for assessing potential impact on the Bulk-Power System through the standards development process (P.54). Accordingly, the drafting team has posted the proposed Benchmark GMD Event Description whitepaper on the project page along with the standard for comment during this comment period. The drafting team believes the proposed benchmark GMD event is consistent with existing utility best practices, provides the consistent assessment criteria required by the FERC order, and supports assessment of the parameters specified by the directives.

   Do you agree that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779? If you do not agree, please provide specific technically justified alternatives or suggestions for the drafting team to consider.

   ☐ Yes
   X☐ No

Comments: The geoelectric field proposed in the draft GMD standard lacks a peer review by a group of space weather experts nor has it been published in a reviewed journal. Additionally, there exists numerous available recorded sets of data that is in direct contradiction of the assumptions underlying the spatial averaging approach taken. Furthermore, there is no physical phenomena that supports an extremely huge aurora to cause an enhanced or focused geoelectric field in to a size on the order of 100km by 100km. An important standard such as this one which potentially could have a very high impact should not be based on a new spatial averaging theory for which there is violent disagreement by experts in the space weather community.
This project is identified as a Low Frequency of occurrence by potentially High Impact event. As such the GMD Task Force team should spend some time analyzing the consequences of a High Impact event. If in fact this analyzes suggests that there is a possibility of consequences that are intolerable, this would demand a more serious development of the GMD standard that is completely vetted and reviewed by an independent group of Space Weather experts before the standard can be approved.
Detailed comments from Emprimus LLC were submitted to the NERC Drafting team on Friday, May 16, 2014, and should be considered as part of these comments.

4. **Implementation**. Order No. 779 does not direct a specific Implementation Plan, but sets an expectation for a multi-phased approach and consideration for the availability of tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments. The drafting team is proposing a phased implementation of TPL-007-1 over a 4-year

period. The Implementation Plan provides 1) time for entities to develop the required models; 2) proper sequencing of assessments; and 3) time for development of viable Corrective Action Plans, which may require entities to develop, perform, and validate studies, assessments, and procedures. Do you support the approach taken by the drafting team in the proposed Implementation Plan, and if you are an applicable entity in the proposed standard is the proposed time frame and sequencing realistic?

☐ Yes
X☐ No

Comments: The geoelectric field proposed in the draft GMD standard lacks a peer review by a group of space weather experts nor has it been published in a reviewed journal. Additionally, there exists numerous available recorded sets of data that is in direct contradiction of the assumptions underlying the spatial averaging approach taken. Furthermore, there is no physical phenomena that supports an extremely huge aurora to cause an enhanced or focused geoelectric field in to a size on the order of 100km by 100km. An important standard such as this one which potentially could have a very high impact should not be based on a new spatial averaging theory for which there is violent disagreement by experts in the space weather community.
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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.

Description of Current Draft

This is the first draft of the proposed Reliability Standard. It is posted for 45-day comment and initial ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June 2014
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

This is a corrected copy of Draft 1 posted on June 17, 2014. The version posted on June 13, 2014, contained a typographical error in numbering of Requirement R3 subpart 3.3.1.

Effective Dates

The definition shall become effective on the first day of the first calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance shall be implemented over a 4-year period as described in the Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale: Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, they are not included in the applicability for this standard.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes,

agreements, and email correspondence that identifies that agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.

R2. Responsible entities as determined in Requirement R1 shall maintain System models and geomagnetically-induced current (GIC) System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Responsible entities as determined in Requirement R1 shall have evidence in either electronic or hard copy format that it is maintaining System models and geomagnetically-induced current (GIC) System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

R3. Responsible entities as determined in Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Studies shall include the following conditions:

3.1.1. System peak Load for at least one year within the Near-Term Transmission Planning Horizon;

3.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

3.2. Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

3.3. The GMD Vulnerability Assessment shall be provided within 90 days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability related need.

3.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M3. Responsible entities as determined in Requirement R1 shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R3. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity who has indicated a reliability related need as specified in Requirement R3. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R3.

Rationale for Requirement R3:

The GMD Vulnerability Assessment includes steady state power flow analysis and supporting studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

R4. Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage limits for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Responsible entities as determined in Requirement R1 shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage limits for its System in accordance with Requirement R4.

Rationale for Requirement R4:

System steady state voltage limits for GMD Vulnerability Assessment may by different from the limits used in the TPL-001 Planning Assessment. The planner must adhere to established limits that ensure the planned System achieves the performance requirements in Table 1.

R5. Responsible entities as determined in Requirement R1 shall provide geomagnetically-induced current (GIC) flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer. The GIC flow information shall include for each applicable power transformer: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

5.1 Maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1; and

5.2 Effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 for each applicable power transformer where the Maximum effective GIC value for the worst case geoelectric field orientation exceeds 15 Amperes per phase.

M5. Responsible entities as determined in Requirement R1 shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided geomagnetically-induced current (GIC) flow information to each Transmission Owner and Generator Owner that owns an applicable power transformer as specified in Requirement R5.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment.

The GIC flows provided in part 5.1 are used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The GIC flows provided by part 5.2 and 5.3 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:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for each of its solely and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase. The thermal impact assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

6.1. Be based on the effective GIC flow information provided in Requirement R5; and

6.2. Document assumptions used in the analysis; and

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities as determined in Requirement R1 within 12 calendar months of receiving GIC flow information specified in Requirement R5.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its applicable solely and jointly owned power transformers where maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase as specified in Requirement R6.

Rationale for Requirement R6:
The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the Transformer Thermal Impact Assessment white paper posted on the project page.
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R7. Responsible entities as determined in Requirement R1that 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. The Corrective Action Plan shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R7. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity who has indicated a reliability related need as specified in Requirement R7. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments in accordance with Requirement R7.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Load loss as well as generation loss is acceptable as a consequence of the planning event.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.
d. System steady state voltages shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner in accordance with Requirement R4.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation during the GMD event[3]	Yes[4]	Yes[4]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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.
4. 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. 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 during a GMD event.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude to be used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α can be computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, 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.

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[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, to be used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α, β is applied to the reference geolectric field using the following equation to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available the planning entity should use a β factor of 1 or a technically-justified value.

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

The earth models used to calculate Table 3 for the United States were obtained from publicly available magnetotelluric data that is published on the U. S. Geological Survey website[3]. The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. NRCan also has developed some models for sub-regions which should be used when available. Because all models in Table 3 are approximations, a planner can substitute a technically justified earth model for its planning area when available.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

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. Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geoelectric field.

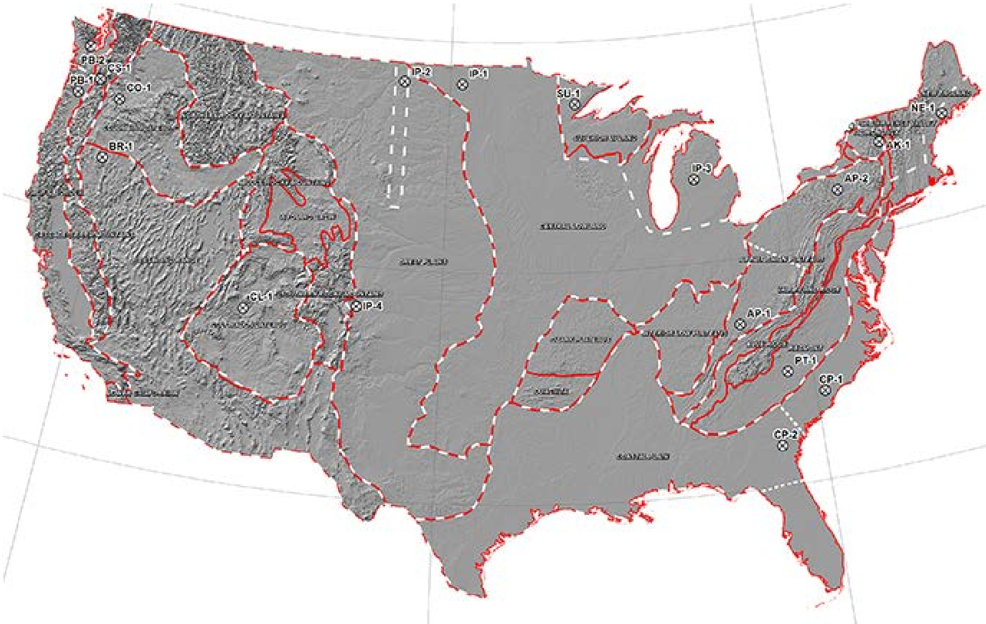

Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series where a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

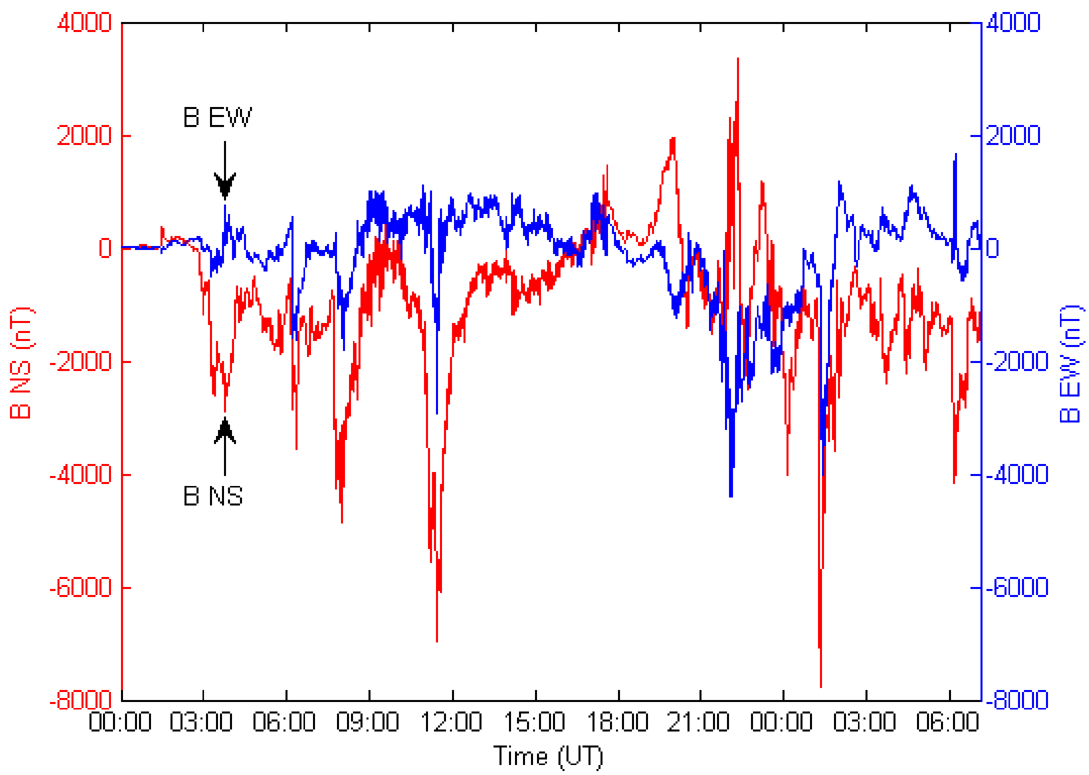

Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

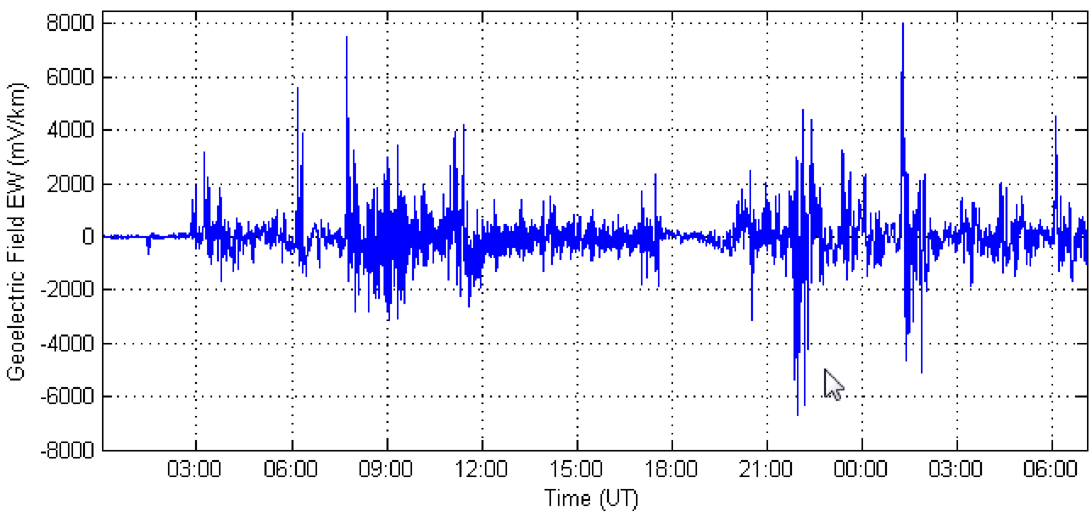


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

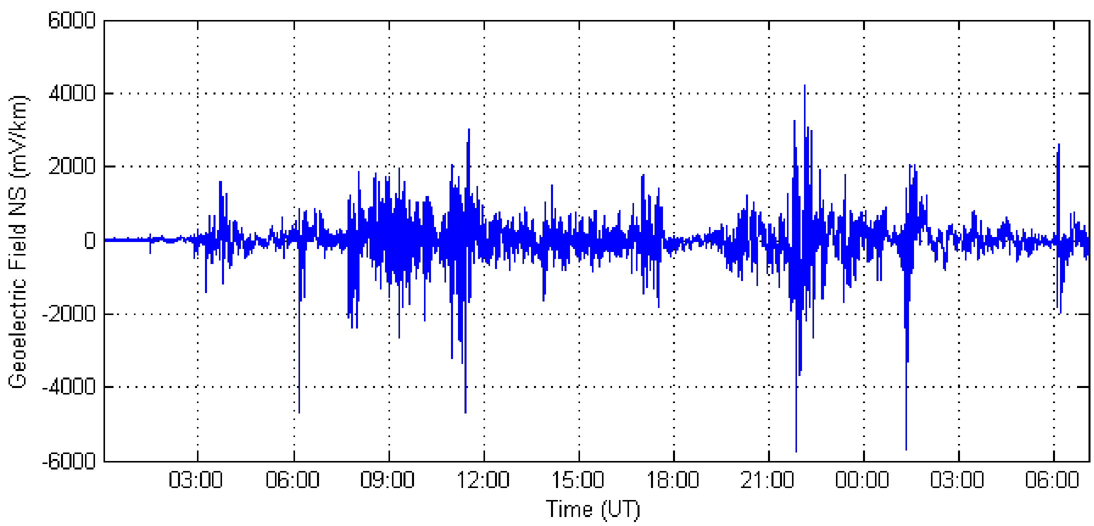


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not maintain System models and geomagnetically-induced current (GIC) System models of the responsible entity's planning area for performing the studies needed to complete

						GMD Vulnerability Assessment(s).
R3	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R3 Parts 3.1 through 3.3.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R3 Parts 3.1 through 3.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R3 Parts 3.1 through 3.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R4	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage limits for its System during the benchmark GMD event described in

						Attachment 1 as required.
R5	Long-term Planning	Medium	N/A	N/A	The responsible entity failed to provide one of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.	The responsible entity failed to provide two of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer; OR The responsible entity did not provide geomagnetically-induced current (GIC) flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.
R6	Long-term Planning	High	The responsible entity failed to conduct an assessment of thermal impact for 5% or less of its solely owned and jointly owned applicable power transformers where the maximum effective	The responsible entity failed to conduct an assessment of thermal impact for more than 5% up to (and including) 10% of its solely owned and jointly owned applicable power transformers where the	The responsible entity failed to conduct an assessment of thermal impact for more than 10% up to (and including) 15% of its solely owned and jointly owned applicable power transformers where the	The responsible entity failed to conduct an assessment of thermal impact for more than15% of its solely owned and jointly owned applicable power transformers where the maximum effective

			geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity conducted an assessment of thermal impact of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase but did so more than 12 calendar months and less than or equal to 13 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity conducted an assessment of thermal impact of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase but did so more than 13 calendar months and less than or equal to 14 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include two of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity conducted an assessment of thermal impact of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase but did so more than 14 calendar months and less than or equal to 15 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include three of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity conducted an assessment of thermal impact of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase but did so more than 15 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include four of the required elements as listed in Requirement R6 parts 6.1 through 6.4.

R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 parts 7.1 and 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 parts 7.1 and 7.3.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7 parts 7.1 and 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

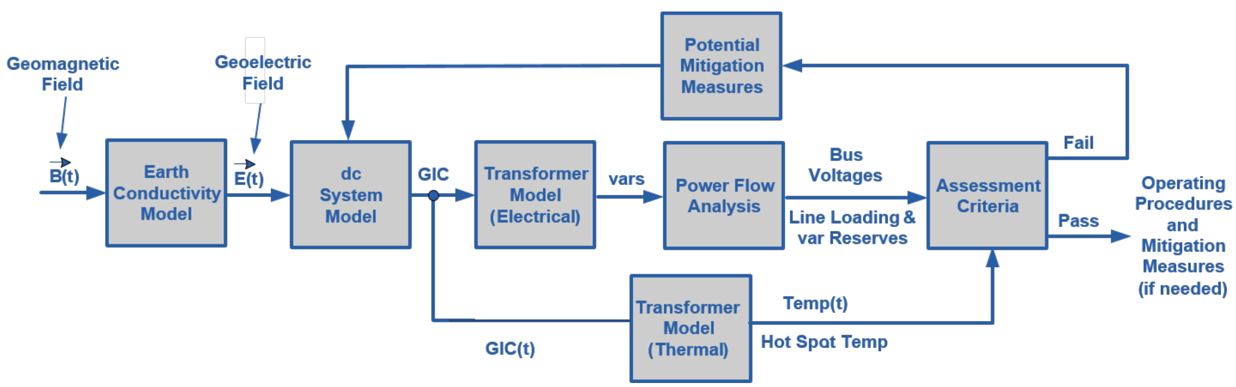
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R3

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC time series information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC system model and must be provided to the entity responsible for conducting the thermal impact assessment.

The maximum effective GIC value provided in part 5.1 is used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The effective GIC time series, GIC(t), provided in part 5.2 is used to conduct the transformer thermal impact assessment (see white paper for details).

The peak GIC value of 15 amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low. Additional information is available in the transformer thermal impact assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white paper for additional information.

Requirement R7

Technical considerations for GMD mitigation planning are available in Chapter 5 of the GMD Planning Guide. Additional information is available in the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.

Description of Current Draft

This ~~draft~~ is the first ~~posting~~draft of the proposed ~~standard.~~Reliability Standard. It is posted for ~~a~~ ~~30~~45-day ~~informal~~ comment and initial ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June 2014
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

The definition shall become effective on the first day of the first calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance shall be implemented over a 4-year period as described in the Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events ~~within the Near-Term Transmission Planning Horizon~~.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Planning Coordinator with a ~~Planning Coordinator~~planning area that includes a ~~power transformer with a high side, wye-grounded winding connected at 200 kV~~Facility or ~~higher~~Facilities specified in 4.2;

4.1.2 Transmission Planner with a ~~Transmission Planning~~planning area that includes a ~~power transformer with a high side, wye-grounded winding connected at 200 kV~~Facility or ~~higher~~Facilities specified in 4.2;

4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

4.2. Facilities:

~~4.1.3~~4.2.1 Facilities that include power transformer(s) with ~~a~~ high side, wye-grounded winding ~~connected at~~with terminal voltage greater than 200 kV ~~or higher~~.

~~Generation Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher~~

Rationale: Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, they are not included in the applicability for this standard.

5. **Background:**

During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator ~~and~~ , in conjunction with each of its Transmission ~~Planner shall maintain ac System models and geomagnetically-induced current (GIC) System~~

~~models within its respective area for~~ Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete ~~its~~ GMD Vulnerability Assessment~~. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. The System models shall include:~~(s). *[Violation Risk Factor: ~~Medium]~~Low] [Time Horizon: Long-term Planning]*

~~**1.1.** Existing Facilities~~

~~**1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.~~

~~**1.3.** New planned Facilities and changes to existing Facilities~~

~~**1.4.** Real and reactive Load forecasts~~

~~**1.5.** Known commitments for Firm Transmission Service and Interchange~~

~~**1.6.** Resources (supply or demand side) required for Load~~

M1. Each Planning Coordinator ~~and Transmission Planner~~, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and email correspondence that identifies that agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.

R2. Responsible entities as determined in Requirement R1 shall maintain System models and geomagnetically-induced current (GIC) System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Responsible entities as determined in Requirement R1 shall have evidence in either electronic or hard copy format that it is maintaining ~~ac~~ System models and geomagnetically-induced current (GIC) System models ~~within its respective area, using data consistent with MOD standards including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.~~of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement ~~R1~~R2:

A GMD Vulnerability Assessment requires a ~~dc~~ GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. ~~Details~~Guidance for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The ~~ac~~ System model specified in Requirement R2 is used in conducting steady -state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The projected System condition for GMD planning may include adjustments to ~~posture~~ the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

~~R2.~~**R3.** ~~**R2.** Each Planning Coordinator and Transmission Planner~~Responsible entities as determined in Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon ~~for its respective area~~ once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Studies shall include the following conditions:

3.1.1. System peak Load for at least one year within the Near-~~t~~Term Transmission Planning Horizon~~.~~;

3.1.2. System Off-Peak Load for at least one year within the Near-~~t~~Term Transmission Planning Horizon.

3.2. Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

3.3. ~~**M2.** Each Planning~~ The GMD Vulnerability Assessment shall be provided within 90 days of completion to the responsible entity's Reliability Coordinator~~and~~, adjacent Planning Coordinators, adjacent Transmission ~~Planner~~Planners, and to any functional entity that submits a written request and has a reliability related need.

3.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M3. Responsible entities as determined in Requirement R1 shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement ~~R2.~~ R3. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity who has indicated a reliability related need as specified in Requirement R3. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R3.

Rationale for Requirement ~~R2~~R3:

The GMD Vulnerability Assessment includes steady ~~-~~state power flow analysis and supporting studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

R4. ~~Each~~ Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage limits for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning ~~Coordinator and~~]*

M4. Responsible entities as determined in Requirement R1 shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage limits for its System in accordance with Requirement R4.

Rationale for Requirement R4:

System steady state voltage limits for GMD Vulnerability Assessment may by different from the limits used in the TPL-001 Planning Assessment. The planner must adhere to established limits that ensure the planned System achieves the performance requirements in Table 1.

R5. Responsible entities as determined in Requirement R1 shall provide geomagnetically-induced current (GIC) flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission ~~Planner that determines~~Owner and Generator Owner in the planning area that owns an applicable power transformer. The GIC flow information shall include for each applicable power transformer: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

5.1 Maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1; and

5.2 Effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 for each applicable power transformer where the Maximum effective GIC value for the worst case geolectric field orientation exceeds 15 Amperes per phase.

M5. Responsible entities as determined in Requirement R1 shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided geomagnetically-induced current (GIC) flow information to each Transmission Owner and Generator Owner that owns an applicable power transformer as specified in Requirement R5.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment.

The GIC flows provided in part 5.1 are used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The GIC flows provided by part 5.2 and 5.3 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:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for each of its solely and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase. The thermal impact assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

6.1. Be based on the effective GIC flow information provided in Requirement R5; and

6.2. Document assumptions used in the analysis; and

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities as determined in Requirement R1 within 12 calendar months of receiving GIC flow information specified in Requirement R5.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its applicable solely and jointly owned power transformers where maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase as specified in Requirement R6.

Rationale for Requirement R6:

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

~~R3.~~R7. Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability Assessment conducted in Requirement ~~R2~~R3 that ~~its~~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. The Corrective Action Plan shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

~~3.1.~~7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

~~8.1.~~ Be reviewed in subsequent GMD Vulnerability Assessments ~~for continued validity and implementation status of identified~~ until it is determined that the System ~~Facilities and Operating Procedures.~~

~~**M3.** Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R3.~~

~~**R4.** Each Planning Coordinator and Transmission Planner shall have criteria for acceptable System steady state voltage limits for its System during the GMD conditions described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~3.2.~~7.2. ~~**M4.** Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of~~meets the ~~criteria for acceptable System steady state voltage limits for its System in accordance with Requirement R4.~~performance requirements contained in Table 1.

~~Rationale for Requirement R4:~~

~~System steady state voltage limits for GMD Vulnerability Assessment may by different from the limits used in the TPL-001 Planning Assessment. The planner must adhere to established limits that ensure the planned System achieves the performance requirements in Table 1.~~

~~**R5.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD Vulnerability Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*~~

~~**M5.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the GMD Vulnerability Assessment in accordance with Requirement R5.~~

~~3.3.~~7.3. ~~**R6.** Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to~~Be provided within 90 days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and ~~Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and~~ to any functional entity that submits a written request and has a reliability related need ~~and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ .

~~3.3.1.~~7.3.1. **~~6.1~~** If a recipient of the ~~GMD Vulnerability Assessment results~~ Corrective Action Plan provides documented comments on the results, the ~~respective Planning Coordinator or Transmission Planner~~responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

~~**M6.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices~~**M7.** Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R7. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its ~~GMD Vulnerability Assessment results and~~ Corrective Action Plan, if any, ~~to~~within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators ~~and~~, adjacent Transmission Planners ~~within 90 days of completion~~, and to any functional entity who has indicated a reliability related need ~~within 30 days of a written request. Each Planning Coordinator and Transmission Planner~~as specified in Requirement R7. Responsible entities as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its ~~GMD Vulnerability Assessment results~~Corrective Action Plan within 90 calendar days of receipt of those comments in accordance with Requirement ~~R5~~R7.

~~Rationale for Requirement R6:~~

~~Distribution of GMD Vulnerability Assessment results and Corrective Action Plans provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies and planned mitigation measures may affect neighboring systems and should be taken into account by planners. Additionally, this GIC information is essential for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment.~~

~~**R7.** Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~

~~**6.1.** Be based on the benchmark GMD event described in Attachment 1 with peak geomagnetically-induced current (GIC) flows as modeled in the steady-state analysis conducted in Requirement R2~~

~~**6.2.** Document assumptions used in the analysis~~

~~**6.3.** Describe suggested actions and supporting analysis to mitigate the impact of geomagnetically-induced currents, if any.~~

~~**M7.** Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher as specified in Requirement R7.~~

~~Rationale for Requirement R7:~~   ~~The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page.~~   ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

~~**R8.** Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M8.** Each Transmission Owner and Generator Owner shall have dated evidence such as postal receipts or email confirmation that it has provided a copy of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded wye windings connected at 200 kV or higher as specified in Requirement R7 to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located within the timeframe prescribed in Requirement R8.~~

Table 1 –Steady State Planning Events

Steady State:

a. ~~The System shall remain stable.~~Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. ~~Consequential~~ Load ~~L~~loss as well as generation loss is acceptable as a consequence of ~~P8~~the planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

d. System steady state voltages shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner in accordance with Requirement R4.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	~~Non-Consequential~~ Load Loss Allowed
~~P8~~ GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation during the GMD event[3]	Yes[4]	Yes[4]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event ~~P8~~ are described in Attachment 1 (Benchmark GMD Event).
3. Protection Systems may trip due to the effects of harmonics. ~~P8~~GMD planning analysis shall consider removal of equipment that the planner determines may be susceptible.
4. ~~The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential Load Loss~~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. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of ~~Non-Consequential~~ Load ~~L~~loss or curtailment of Firm Transmission Service is minimized during a GMD event.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude to be used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table ~~1 1~~2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α can be computed with the empirical expression

$$\cancel{\alpha = 0.001 \cdot e^{(0.115 \cdot L)}} \quad \alpha = 0.001 \cdot e^{(0.115 \cdot L)}$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$

For large planning areas that cover more than one scaling factor from Table 2, 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.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table ~~1-1~~2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
~~55~~54	0.~~6~~5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table ~~1-3~~4. The peak geoelectric field, E_{peak}, to be used in a GMD Vulnerability Assessment may be obtained by either

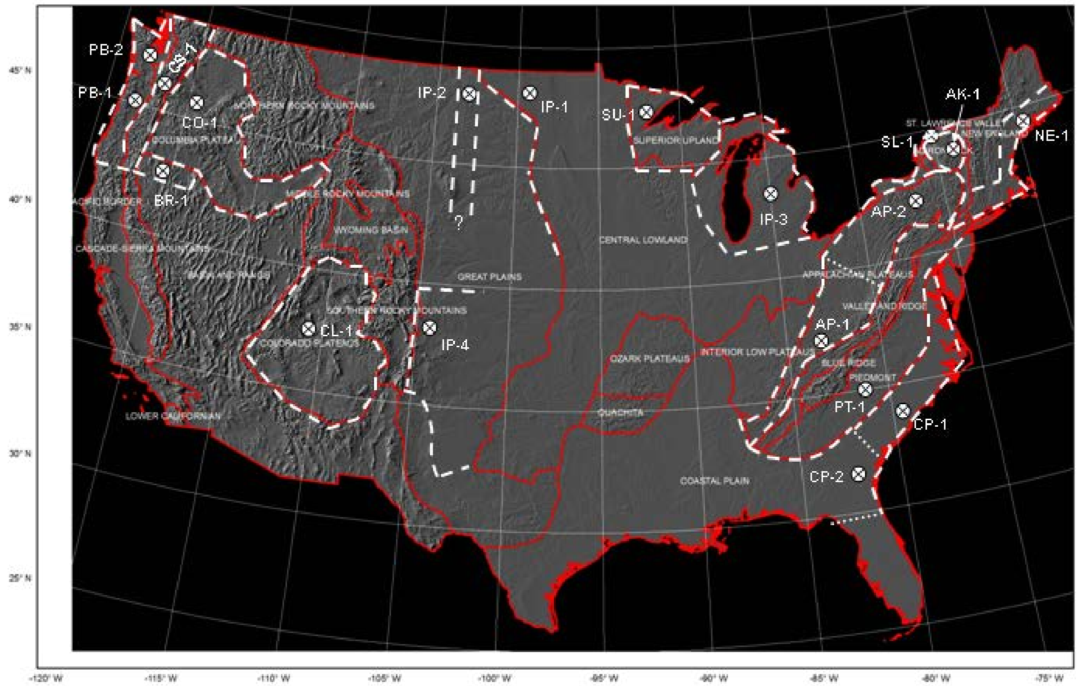
- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table ~~1-2~~3 that correlates to the ground conductivity map in Figure 1~~-1~~ or Figure ~~1-~~2. Along with the scaling factor α, β is applied to the reference geolectric field using the following equation to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available the planning entity should use a β factor of 1 or a technically-justified value.

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

The earth models used to calculate Table ~~1-2~~3 for the United States were obtained from publicly available magnetotelluric data that is published on the U. S. Geological Survey website[3]. The models used to calculate Table ~~1-2~~3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. NRCan also has developed some models for sub-regions which should be used when available. Because all models in Table ~~1-2~~3 are approximations, a planner can substitute a technically justified earth model for its planning area when available.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/



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. Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geoelectric field.

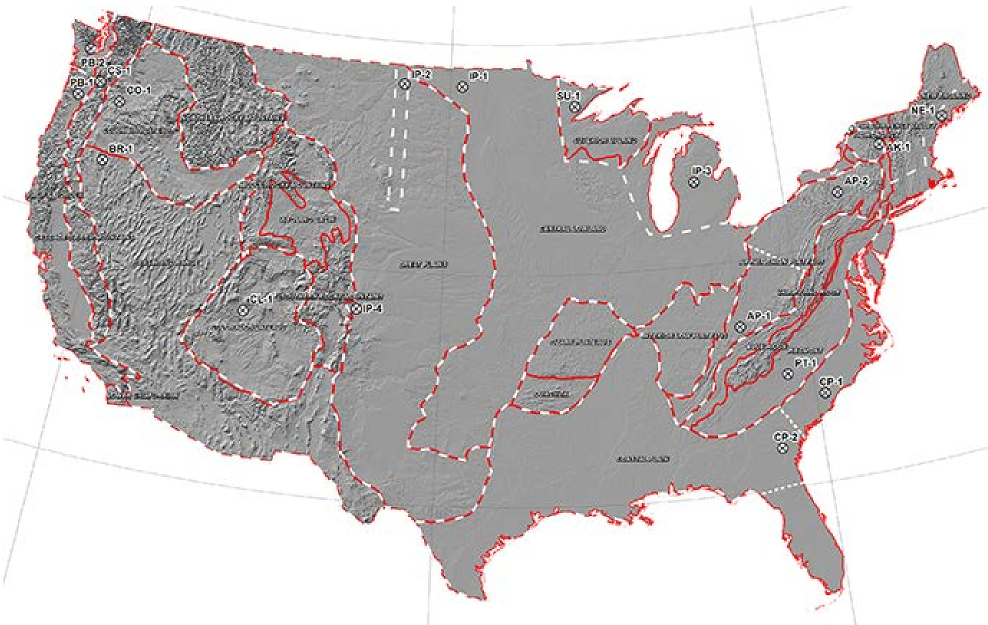


Figure 1~~-1~~: Physiographic Regions of the Continental United States[4]

Figure ~~1-~~2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

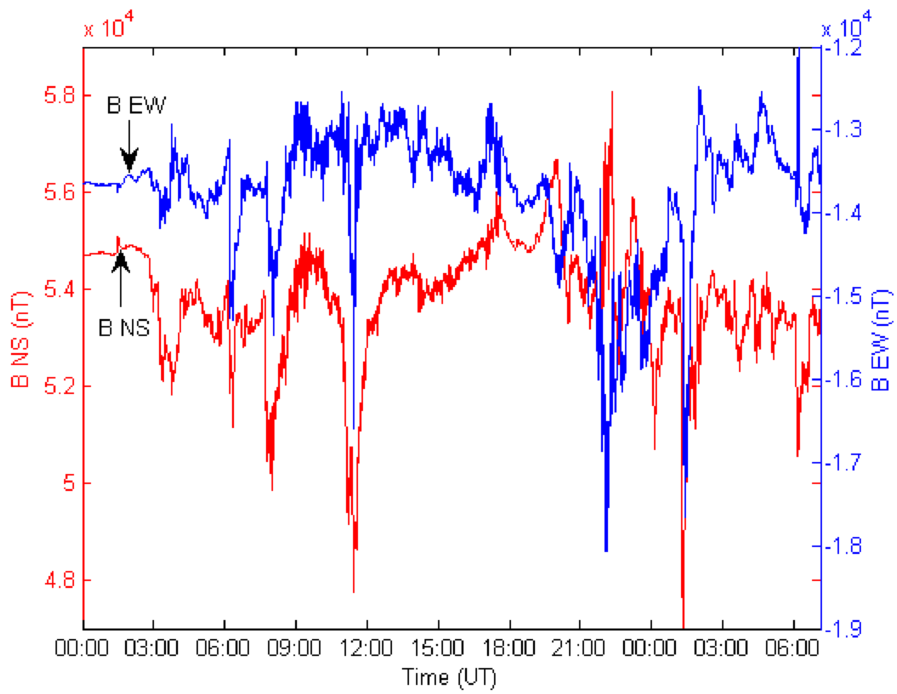
Table ~~1-2~~3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table ~~1-3~~4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 ~~when performing thermal analysis of power transformers~~to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure ~~1-~~3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. ~~1-~~4 and ~~1-~~5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series where a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.



[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

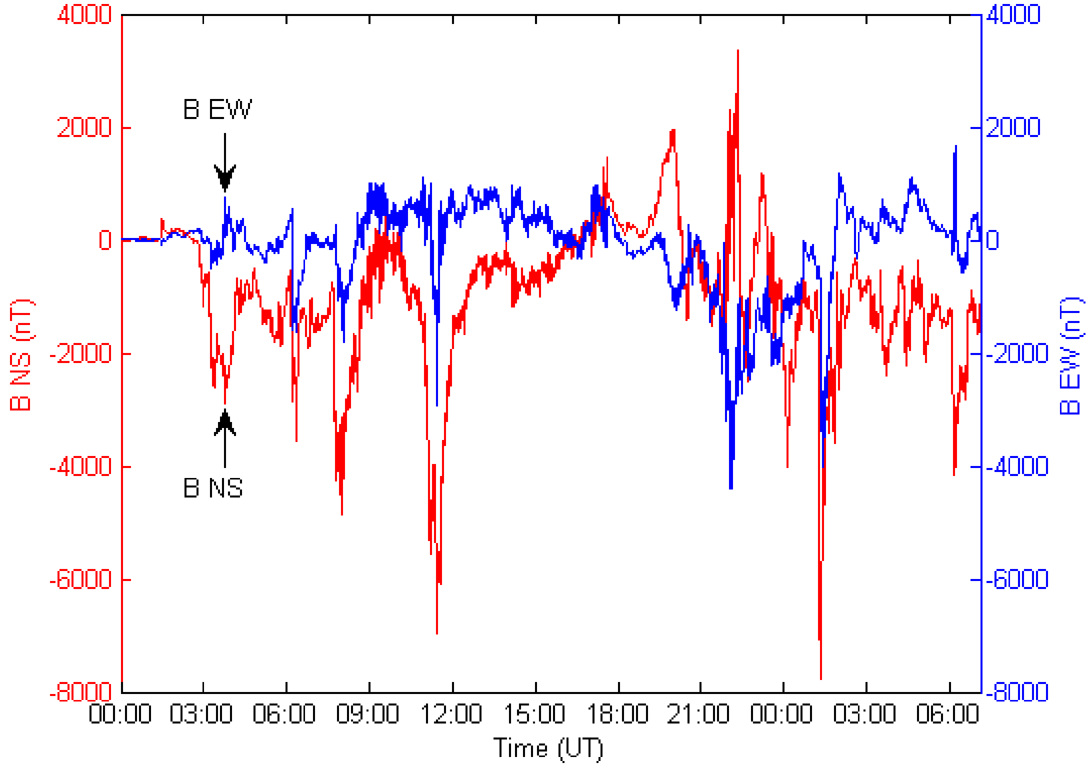
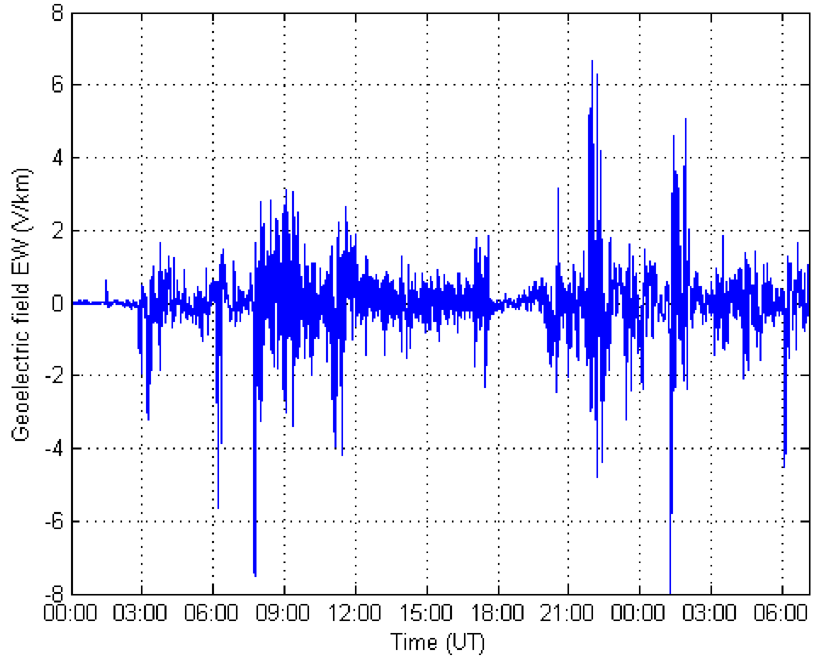


Figure ~~1~~ 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)



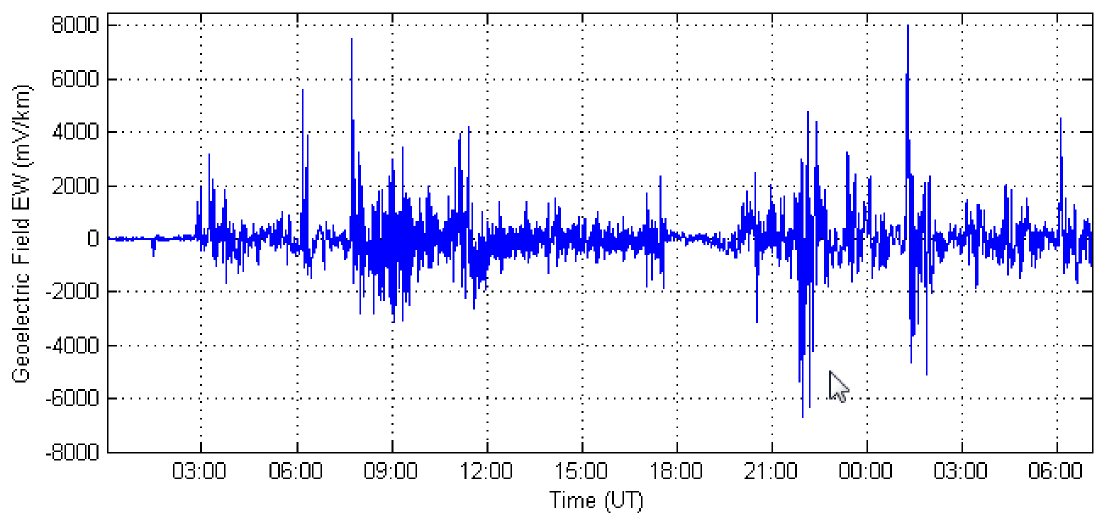
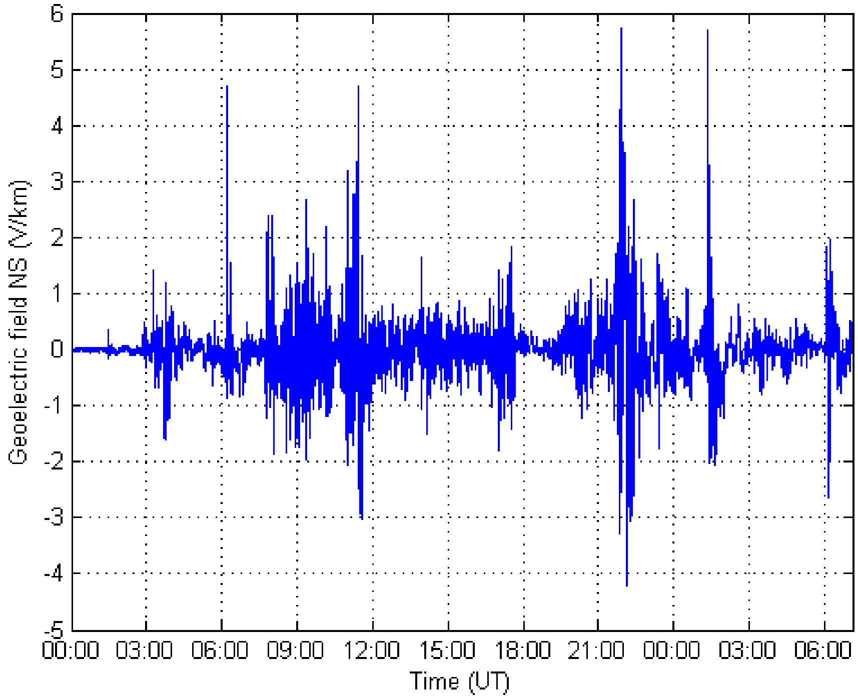


Figure ~~1~~ 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)



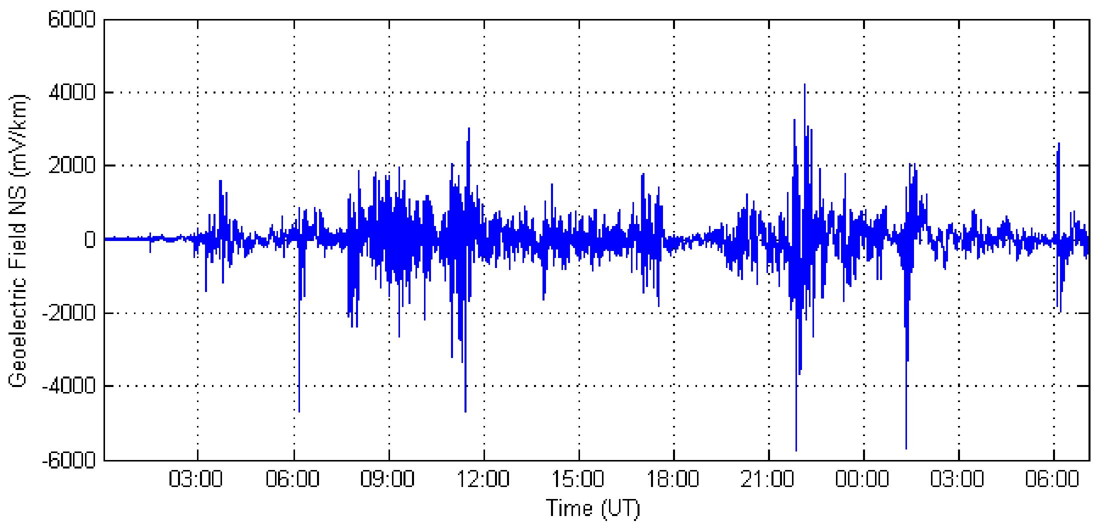


Figure ~~1~~ 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s).
~~R1~~R2	Long-term Planning	Medium	~~The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include one of the elements in Requirement R1, Parts 1.1 through 1.6.~~N/A	~~The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include two of the elements in Requirement R1, Parts 1.1 through 1.6.~~N/A	~~The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include three of the elements in Requirement R1, Parts 1.1 through 1.6.~~N/A	The responsible ~~entity's ac~~entity did not maintain System models and geomagnetically-induced current (GIC) ~~model failed to include four or more~~System models of the ~~elements in Requirement R1, Parts 1.1 through 1.6;~~

						~~OR~~ ~~The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not represent projected System conditions as described in Requirement R1;~~ ~~OR~~ ~~The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not use data consistent with~~responsible entity's planning area for performing the ~~MOD standards including items represented in the Corrective Action Plan.~~studies needed to complete GMD Vulnerability Assessment(s).
~~R2~~R3	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar	The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar	The responsible entity's completed GMD Vulnerability Assessment failed to ~~include one~~satisfy two of the ~~following Parts of~~elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to ~~include two~~satisfy three of the ~~following Parts of~~elements listed in

			months since the last GMD Vulnerability Assessment.	months since the last GMD Vulnerability Assessment~~.~~; OR The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R3 Parts 3.1 through 3.3.	Requirement ~~R2: Part 2~~R3 Parts 3.1 ~~or 2.2~~through 3.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	Requirement ~~R2: Part 2~~R3 Parts 3.1 ~~or 2.2~~through 3.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R4	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage limits for its System during the benchmark GMD event described in Attachment 1 as required.
~~R3~~R5	Long-term Planning	~~High~~Medium	N/A	N/A	The responsible ~~entity's Corrective Action Plan~~entity failed to ~~comply with~~provide one of the elements listed in Requirement ~~R3~~R5 parts ~~3~~5.1 to 5.2	The responsible ~~entity's Corrective Action Plan~~entity failed to ~~comply with~~provide two of the elements listed in Requirement ~~R3~~R5 parts ~~3~~5.1 to 5.2

					to each Transmission Owner and ~~3.2~~Generator Owner in the planning area that owns an applicable power transformer.	to each Transmission Owner and ~~3.2~~Generator Owner in the planning area that owns an applicable power transformer; OR The responsible entity did not ~~have a Corrective Action Plan as required by~~provide geomagnetically-induced current (GIC) flow information to be used for the transformer thermal impact assessment specified in Requirement ~~R3~~R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.
~~**R4**~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity does not have criteria for acceptable System steady state voltage limits for its System during the GMD conditions as required.~~
~~**R5**~~	~~Long-term Planning~~	~~Low~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to~~

						~~determine and identify individual or joint responsibilities for performing required studies.~~
R6	Long-term Planning	~~Medium~~High	~~The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 90 days but less than or equal to 120 days following completion;~~ The responsible entity failed to conduct an assessment of thermal impact for 5% or less of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-	~~The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 120 days but less than or equal to 130 days following its completion;~~ The responsible entity failed to conduct an assessment of thermal impact for more than 5% up to (and including) 10% of its solely owned and jointly owned applicable power transformers where the	~~The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 130 days but less than or equal to 140 days following its completion;~~ The responsible entity failed to conduct an assessment of thermal impact for more than 10% up to (and including) 15% of its solely owned and jointly owned applicable power transformers where the	~~The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 140 days following its completion;~~ The responsible entity failed to conduct an assessment of thermal impact for more than15% of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-

			induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase ; OR The responsible entity ~~distributed~~conducted an assessment of thermal impact of its ~~GMD Vulnerability Assessment results~~solely owned and ~~Corrective Action Plan, if any, to functional entities having a reliability related need who requested~~jointly owned applicable power transformers where the ~~information~~ maximum effective geomagnetically-induced current (GIC) value provided in ~~writing~~Requirement R5 part 5.1 is 15 Amperes or greater per phase but ~~it was~~did so more than ~~30 days but~~12 calendar months and less than or equal to ~~40 days following the request~~13 calendar months of receiving GIC flow	maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity ~~distributed~~conducted an assessment of thermal impact of its ~~GMD Vulnerability Assessment results~~solely owned and ~~Corrective Action Plan, if any, to functional entities having a reliability related need who requested~~jointly owned applicable power transformers where the ~~information~~ maximum effective geomagnetically-induced current (GIC) value provided in ~~writing~~Requirement R5 part 5.1 is 15 Amperes or greater per phase but ~~it was~~did so more than ~~40 days but~~13 calendar months and less than or equal to ~~50 days following the request~~14 calendar months of	maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR The responsible entity ~~distributed~~conducted an assessment of thermal impact of its ~~GMD Vulnerability Assessment results~~solely owned and ~~Corrective Action Plan, if any, to functional entities having a reliability related need who requested~~jointly owned applicable power transformers where the ~~information~~ maximum effective geomagnetically-induced current (GIC) value provided in ~~writing~~Requirement R5 part 5.1 is 15 Amperes or greater per phase but ~~it was~~did so more than ~~50 days but~~14 calendar months and less than or equal to ~~60 days following the request~~15 calendar months of	induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or greater per phase; OR ~~The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4;~~ The responsible entity conducted an assessment of thermal impact of its solely owned and jointly owned applicable power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 Amperes or

			information specified in Requirement R5; OR The responsible entity ~~provided a documented response~~failed to ~~documented comments received from a recipient~~include one of ~~its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 30 days but less than or equal to 40 days following~~ the ~~receipt~~required elements as ~~specified~~listed in ~~Part~~Requirement R6 parts 6.1~~.~~ through 6.4.	receiving GIC flow information specified in Requirement R5; OR The responsible entity ~~provided a documented response~~failed to ~~documented comments received from a recipient~~include two of ~~its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 40 days but less than or equal to 50 days following~~ the ~~receipt~~required elements as ~~specified~~listed in ~~Part~~Requirement R6 parts 6.1~~.~~ through 6.4.	receiving GIC flow information specified in Requirement R5; OR The responsible entity ~~provided a documented response~~failed to ~~documented comments received from a recipient~~include three of ~~its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 50 days but less than or equal to 60 days following~~ the ~~receipt~~required elements as ~~specified~~listed in ~~Part~~Requirement R6 parts 6.1~~.~~ through 6.4.	greater per phase but did so more than 15 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity ~~distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any,~~failed to ~~functional entities having a reliability related need who requested~~ include four of the ~~information~~required elements as listed in ~~writing but it was more than 60 days following the request;~~ ~~OR~~ ~~The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing;~~ ~~OR~~

						~~The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 60 days following the receipt as specified in Part~~Requirement R6 parts 6.1~~;~~ ~~OR~~ ~~The responsible entity did not provide a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan as specified in Part~~ through 6.~~1.~~4.
R7	Long-term Planning	High	~~The responsible entity failed to conduct an assessment of thermal impact for 5% or less of its solely owned and jointly owned power transformers with~~	The responsible ~~entity~~entity's Corrective Action Plan failed to ~~include~~comply with one of the ~~required~~ elements ~~as listed~~ in Requirement R7 parts 7.1 ~~through 7.3;~~	The responsible ~~entity~~entity's Corrective Action Plan failed to ~~include~~comply with two ~~or more~~ of the ~~required~~ elements ~~as listed~~ in Requirement R7 parts 7.1 ~~through 7.3;~~	~~The responsible entity failed to conduct an assessment of thermal impact for more than15% of its solely owned and jointly owned power~~

			~~high-side, wye-grounded windings rated 200 kV or higher.~~N/A	~~OR~~ ~~The responsible entity failed to conduct an assessment of thermal impact for more than 5% up to (~~and ~~including) 10% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher~~7.3.	~~OR~~ ~~The responsible entity failed to conduct an assessment of thermal impact for more than 10% up to (~~and ~~including) 15% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher~~7.3.	~~transformers with high-side, wye-grounded windings rated 200 kV or higher.~~ The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7 parts 7.1 and 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.
~~R8~~	~~Long-term Planning~~	~~Medium~~	~~The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 90 days but less than or equal to 120 days following its completion.~~	~~The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 120 days but less than or equal to 130 days following its completion.~~	~~The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 130 days but less than or equal to 140 days following its completion.~~	~~The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 140 days following its completion.~~ ~~OR~~ ~~The responsible entity did not provide a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner.~~

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement ~~R1~~R2

A GMD Vulnerability Assessment requires a ~~dc~~ GIC System model, which is a dc representation of the System, to calculate GIC flow ~~which is~~. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

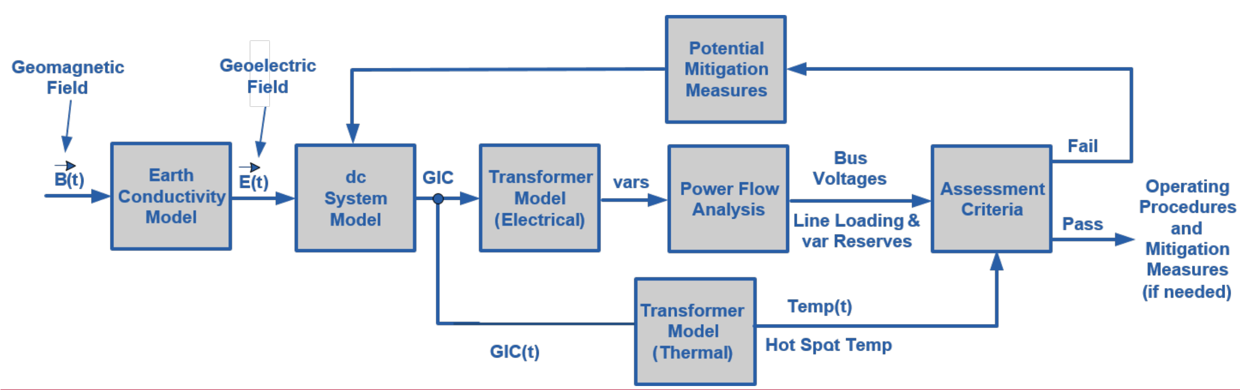
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement ~~R2~~R3

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement ~~R3~~R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC time series information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC system model and must be provided to the entity responsible for conducting the thermal impact assessment.

The maximum effective GIC value provided in part 5.1 is used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The effective GIC time series, GIC(t), provided in part 5.2 is used to conduct the transformer thermal impact assessment (see white paper for details).

The peak GIC value of 15 amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low. Additional information is available in the transformer thermal impact assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white paper for additional information.

Requirement R7

Technical considerations for GMD mitigation planning are available in Chapter 5 of the GMD Planning Guide. Additional information is available in the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

~~**Requirement R7**~~

~~The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page.~~

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a Planning Coordinator planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a Transmission Planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 4-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is 60 calendar days after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is 60 calendar days after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 14 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 14 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 18 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 18 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 36 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R6 shall become effective on the first day of the first calendar quarter that is 36 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 48 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 48 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance ~~During~~ for Geomagnetic Disturbance~~s~~ Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance ~~During~~for Geomagnetic ~~Disturbances~~Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a Planning Coordinator planning area that includes ~~a~~an applicable power transformer ~~with a high side, wye-grounded winding connected at 200 kV or higher~~as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a Transmission Planning area that includes ~~a~~an applicable power transformer ~~with a high side, wye-grounded winding connected at 200 kV or higher~~as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) ~~with a high side, wye-grounded winding connected at 200 kV or higher~~as listed in *section 4.2 Facilities* of the standard; and

Generati~~o~~~~n~~r Owner who owns a power transformer(s) ~~with a high side, wye-grounded winding connected at 200 kV or higher~~ as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 4-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined ~~in~~ by the ~~Steady-state analysis~~responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

~~**Requirements R1 and R5** shall become effective on the first day of the first calendar quarter that is 12~~ **Requirement R1** shall become effective on the first day of the first calendar quarter that is 60 calendar days after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is 60 calendar days after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 14 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 14 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 18 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 18 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 36 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, ~~Requirements R1 and R5~~Requirement R6 shall become effective on the first day of the first calendar quarter that is ~~12~~36 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement ~~R2~~R3, Requirement R4, and **Requirement ~~R6~~R7** shall become effective on the first day of the first calendar quarter that is ~~24~~48 calendar months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. ~~Where approval by an applicable governmental authority is not required, Requirement R2, Requirement R4, and Requirement R6, shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**Requirement R7 and R8** shall become effective on the first day of the first calendar quarter that is 36 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R7 and R8 shall become effective on the first day of the first calendar quarter that is 36 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**Requirement R3** shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.~~ Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 48 calendar months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **July 30, 2014**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages. Project 2013-03 responds to the FERC directives as follows:

- Stage 1. EOP-010-1 – Geomagnetic Disturbance Operations was filed in November, 2013.
- Stage 2. Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the proposed standard will require the applicable entity to develop and implement a plan to mitigate the risk of voltage collapse, uncontrolled separation, or Cascading. The Stage 2 standard must be filed with FERC by January 2015.

The initial draft of TPL-007-1 and supporting white papers were posted for informal comments from April 22 – May 21, 2014. The standard drafting team (SDT) has made several revisions based on stakeholder input.

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

Questions on Draft TPL-007-1

1. **Organization of the Requirements in TPL-007-1.** The SDT has reorganized the standard in response to stakeholder comments. The revised draft is more closely aligned with the steps in the GMD Vulnerability Assessment process. The SDT has also created a flow chart of the overall assessment process. Do these steps address the concerns about the organization of TPL-007-1? If you do not agree or want to provide other recommendations on the organization of the standard please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No

   Comments:

2. **Benchmark GMD Event**. The SDT has provided additional guidance in TPL-007-1 Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event). Changes include how a planning entity with a large geographic area can handle scaling factors in the planning area, and specific guidance on earth conductivity scaling when the planning entity does not have a ground conductivity model. During informal comments, many commenters indicated that they agreed with the proposed benchmark GMD event and no substantive changes have been made. Do you agree that the guidance in TPL-007-1 Attachment 1 provides the required details for applying the proposed benchmark GMD event? If you do not agree or have additional new comments on the proposed benchmark GMD event, please provide specific technically justified suggestions for the SDT to consider.

   ☐ Yes
   ☐ No

   Comments:

3. **Transformer Thermal Impact Assessment.** The SDT revised the requirement for conducting transformer thermal impact assessments. In the revised draft TPL-007-1, only those applicable transformers have calculated GIC flow of 15 Amperes or greater per phase of effective geomagnetically-induced current (GIC) are required to conduct a transformer thermal impact assessment. A review of available transformer thermal models supports this as a conservative screening criteria. Do you agree with the proposed 15 Amperes threshold? If you do not agree or have recommended changes to the transformer thermal impact assessment requirement please provide your suggestion and technical justification, if applicable.

☐ Yes
☐ No

Comments:

4. **Implementation**. The SDT revised the proposed Implementation Plan based on stakeholder comments. The changes provide additional time for completing transformer thermal impact assessments. An overall timeline of four-years from the standard's effective date until completion of all steps in the GMD Vulnerability Assessment process including development of a Corrective Action Plan, if required, has been maintained. Do you support the approach taken by the SDT in the proposed Implementation Plan? If you do not agree with the proposed Implementation Plan, please provide your recommended changes and justification.

   ☐ Yes
   ☐ No

   Comments:

5. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL)**. The SDT has made revisions to conform to changes in the proposed requirements. Do you agree with the VRFs and VSLs for TPL-007-1? If you do not agree, please explain why and provide recommended changes.

   ☐ Yes
   ☐ No

   Comments:

6. **Mitigation Costs.** In directing the development of reliability standards, FERC stated their expectation for NERC and the industry to consider the costs and benefits of mitigation measures to address GMD impacts. Proposed standard TPL-007-1 provides performance requirements but is not prescriptive on mitigation strategies or technologies, if any are necessary. The SDT believes this approach, which is consistent with other planning standards, is the most cost effective means to accomplish the directives in FERC's order. Do you agree with the SDT's approach? If you have

any recommendations or cost information that you would like the SDT to consider please provide it here.

☐ Yes
☐ No

Comments:

7. Are there any other concerns with the proposed standard or white papers that have not been covered by previous questions and comments? If so, please provide your feedback to the SDT.

☐ Yes
☐ No

Comments:

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Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
Draft: June 10, 2014

RELIABILITY | ACCOUNTABILITY

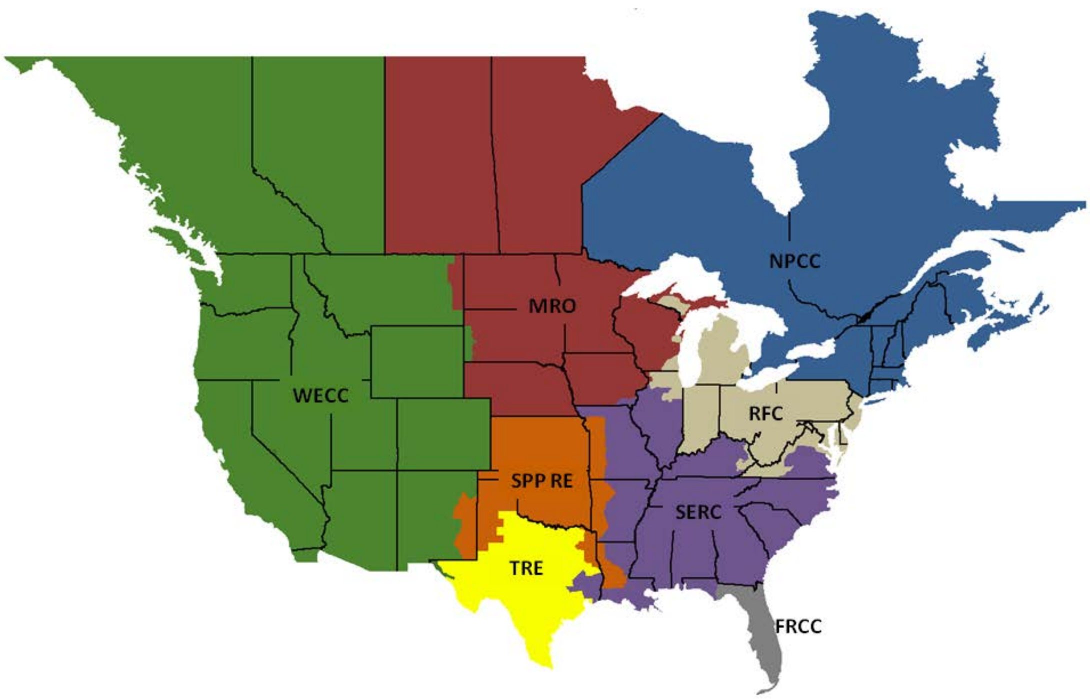



Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

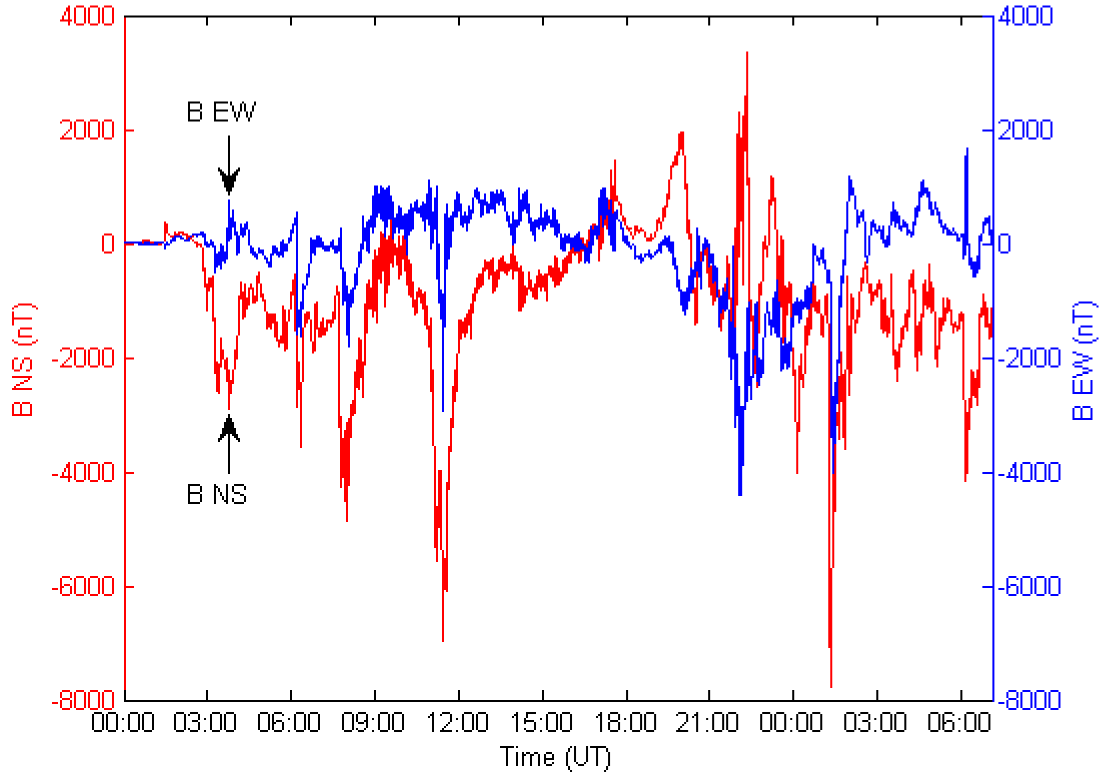


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

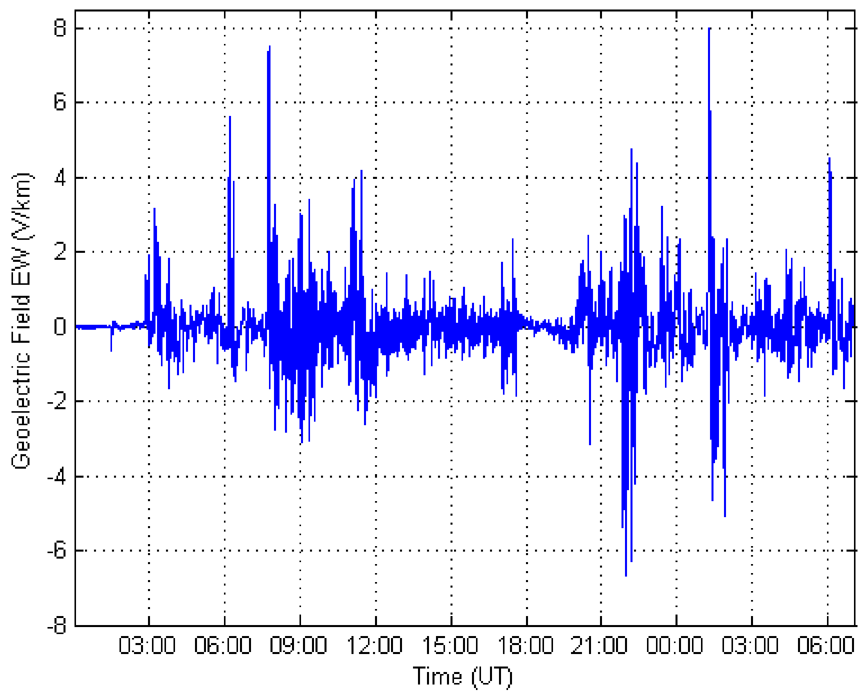


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

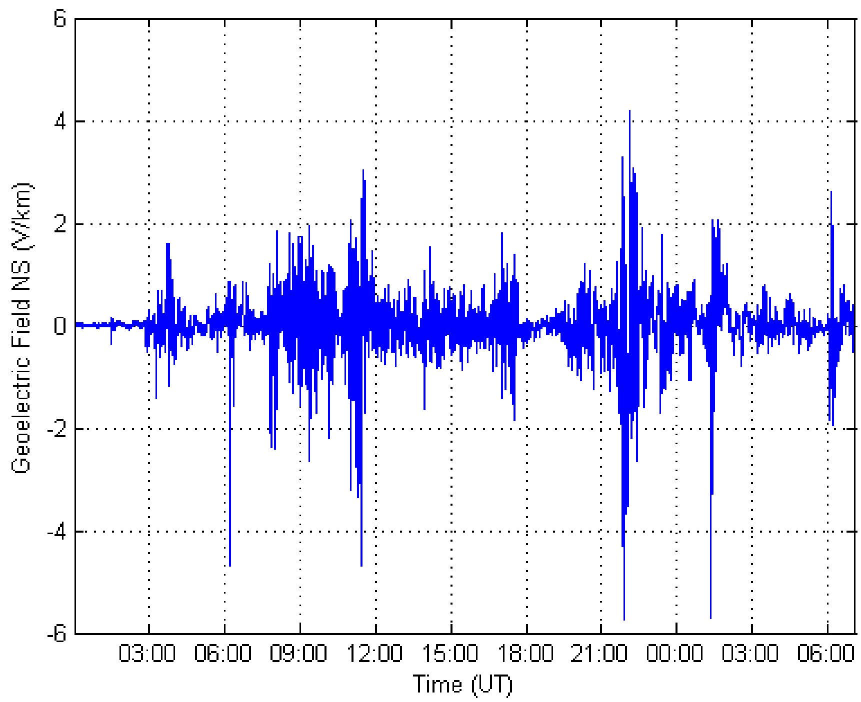


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that any one area is more likely to experience a localized enhanced geoelectric field.

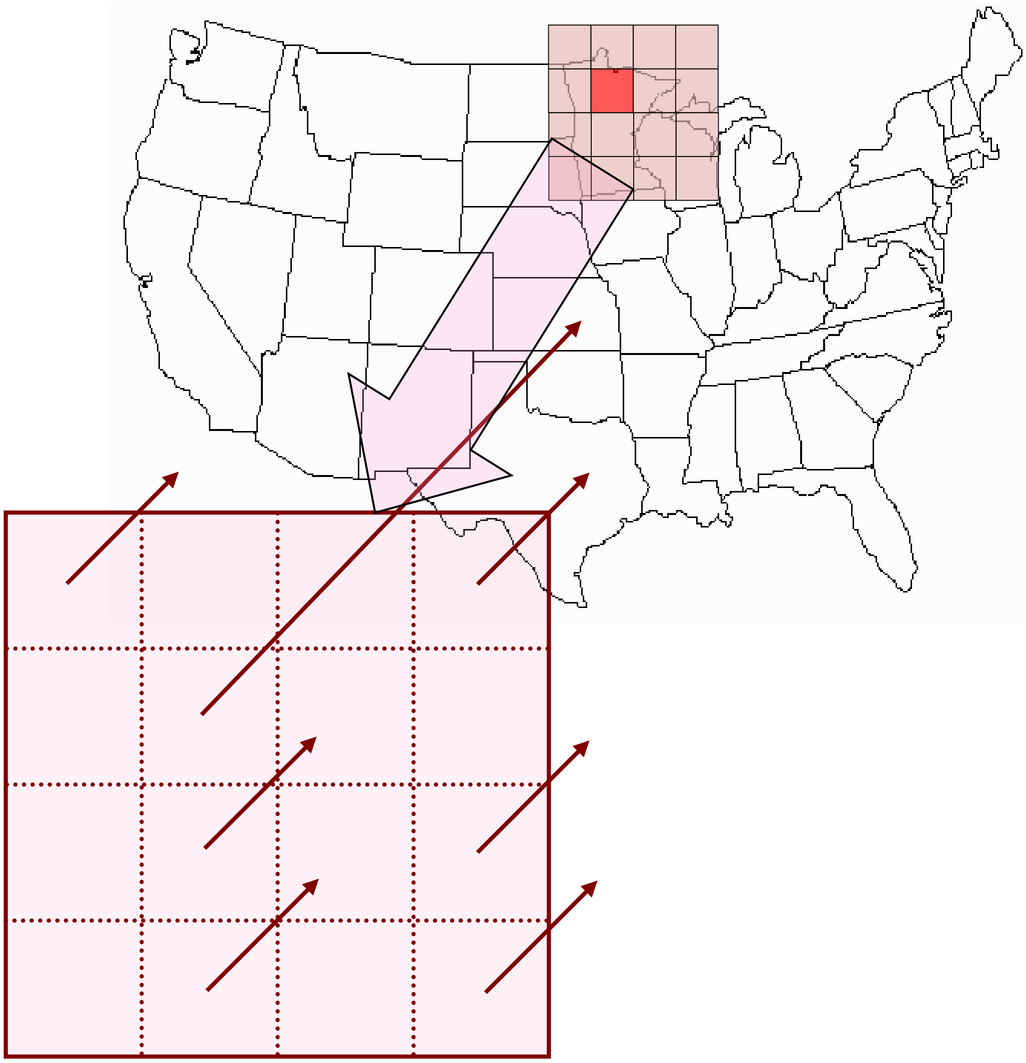


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

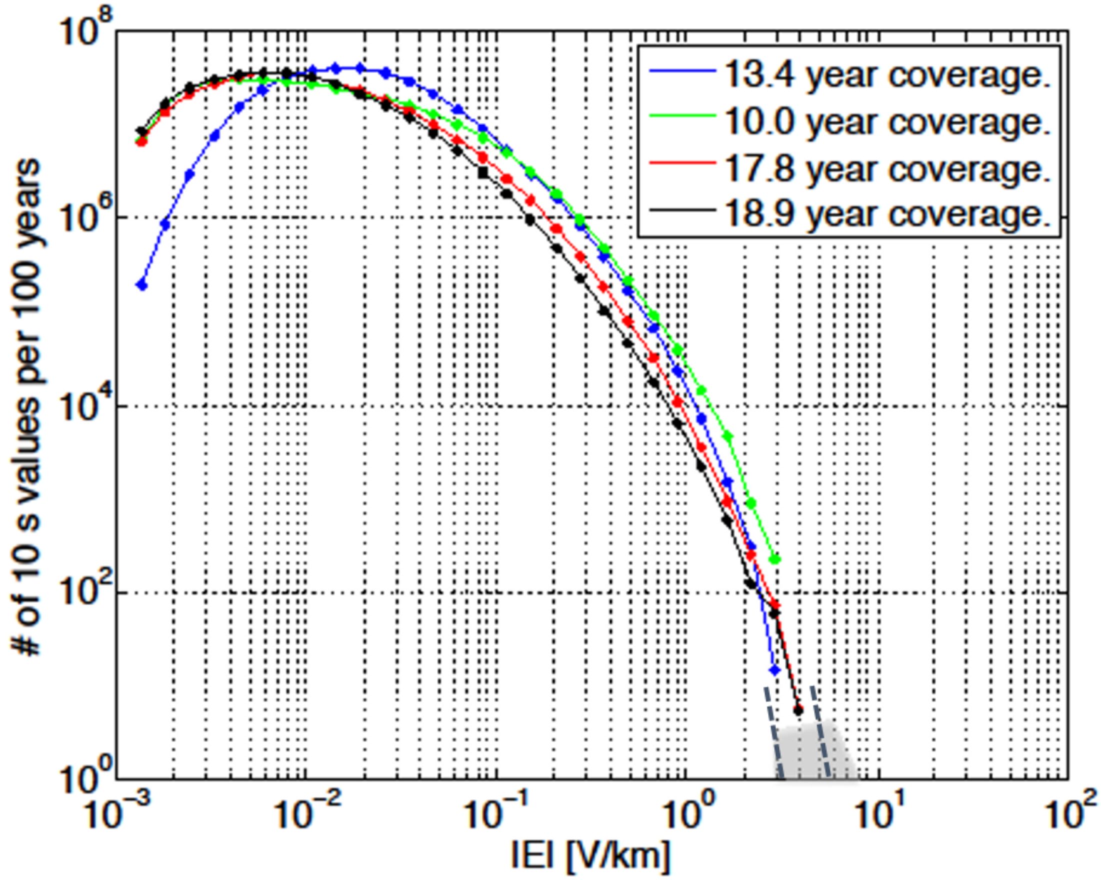


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. Dashed lines represent the values predicted with extreme value analysis. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geo-electric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

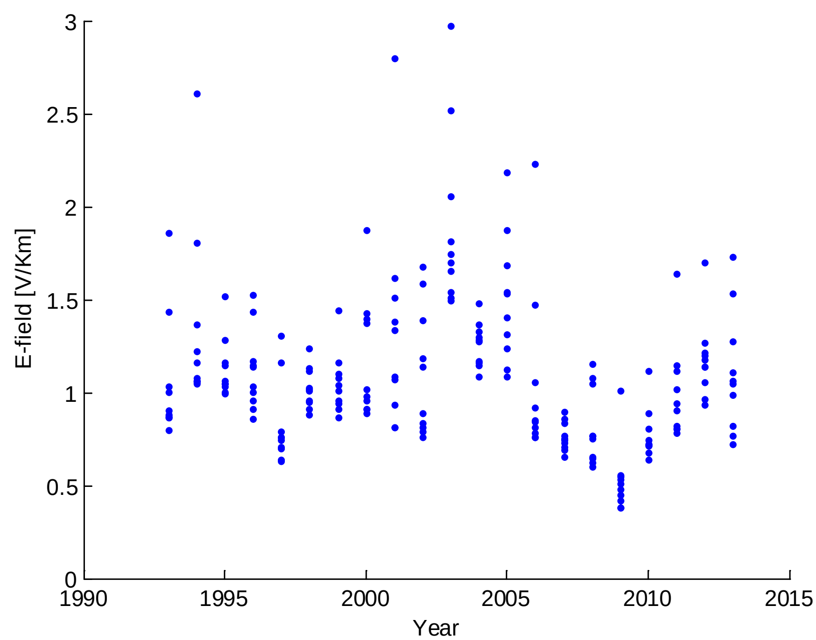


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if we were to obtain repeated samples, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu=\beta_0+\beta_1\cdot\sin\left(\frac{t}{T}+\phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma=\alpha_0+\alpha_1\cdot\sin\left(\frac{t}{T}+\phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu=\beta_0+\beta_1\cdot\sin\left(\frac{t}{T}+\phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistical significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis shows that the geoelectric field amplitude of 8 V/km for the benchmark is conservative for a 100-year return level and it includes an implicit 25 percent engineering margin.

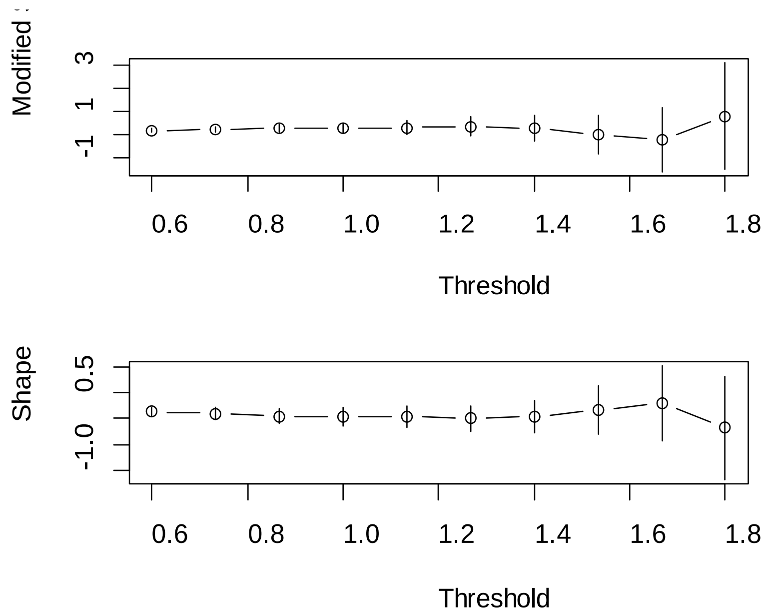


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

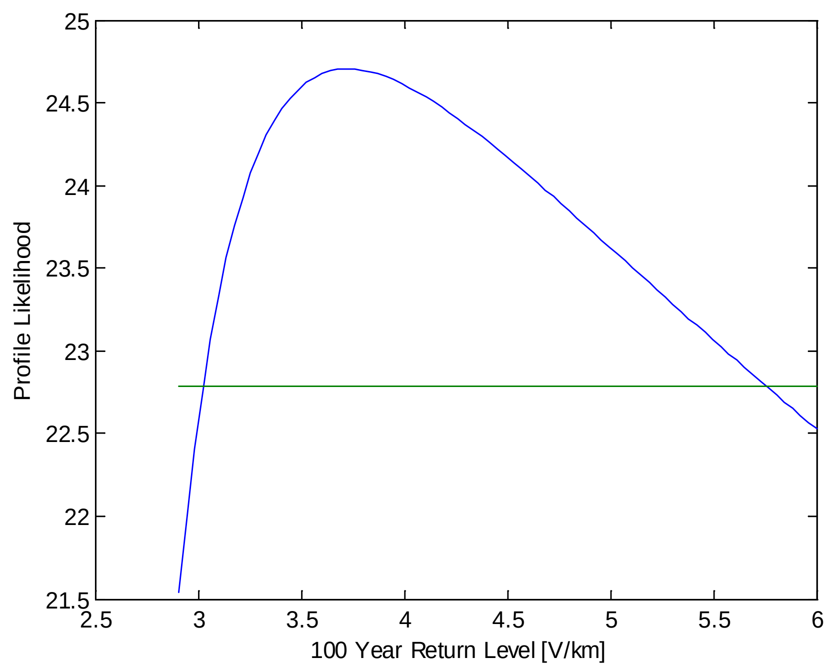


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

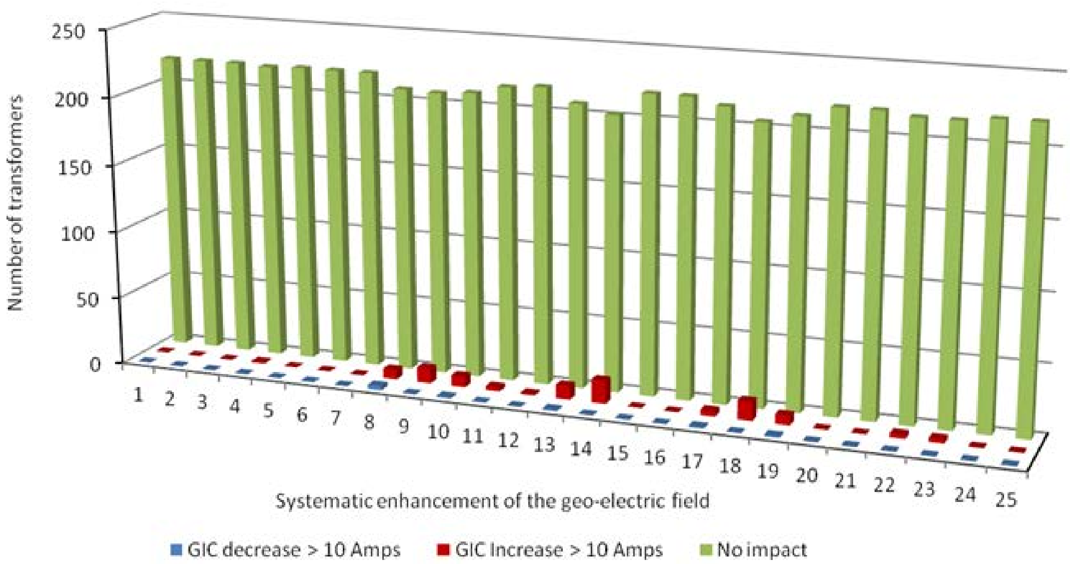


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

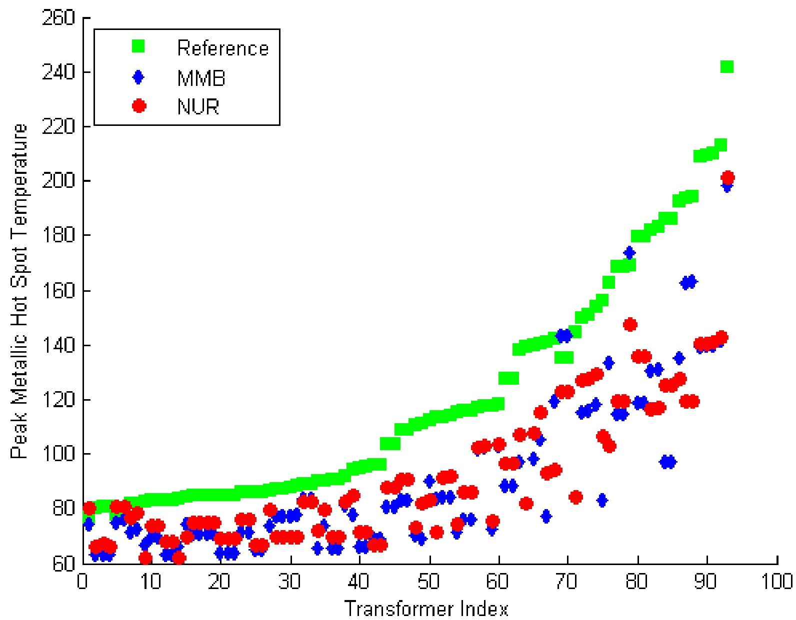


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

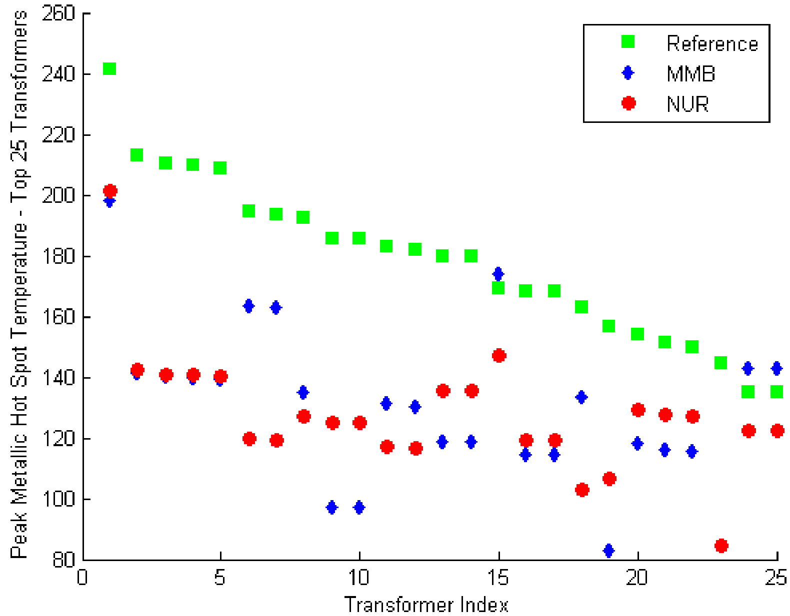


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]. Scaling factors for geomagnetic latitude take in consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \tag{II.1}$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1.0$.

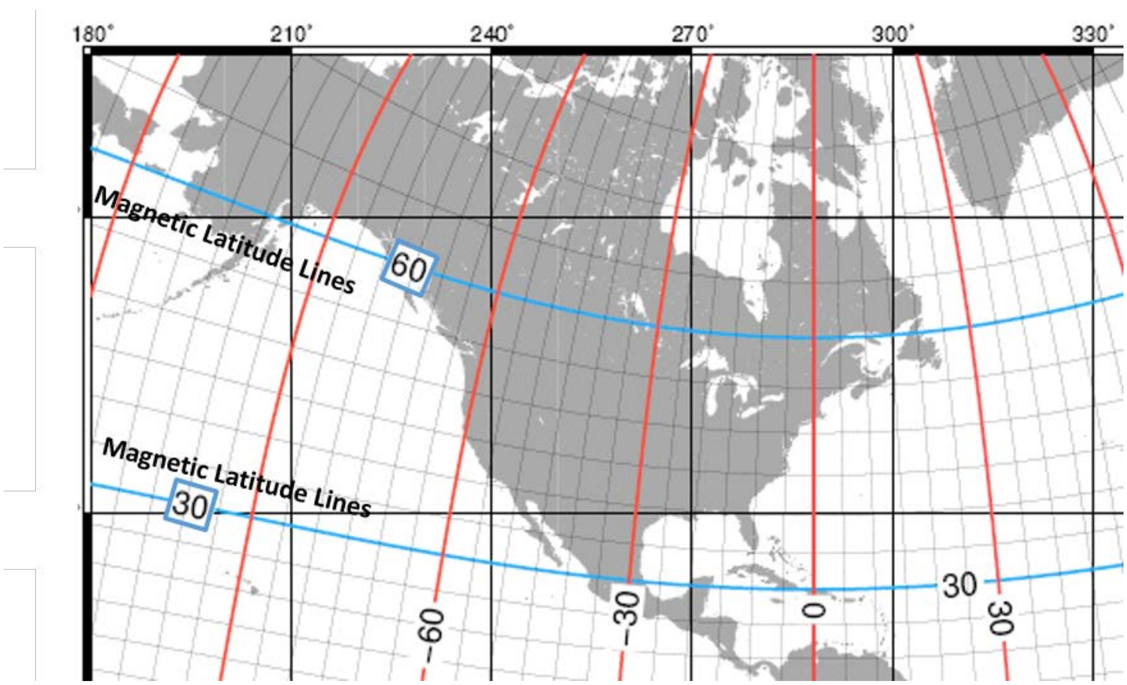


Figure II-1: Geomagnetic Latitude Lines in North America

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6 Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

7 Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \qquad \text{(II.2)}$$

where,
* denotes convolution in the time domain,
z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,
$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,
$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

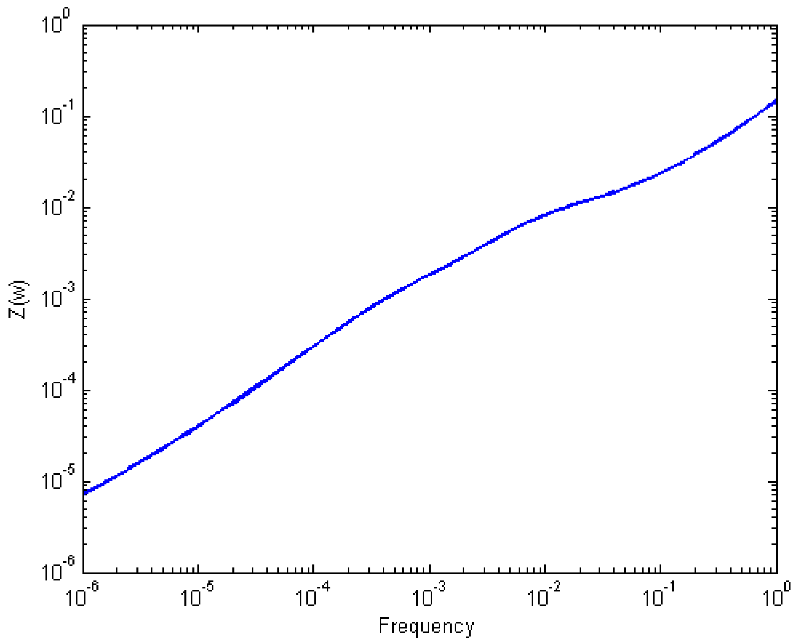


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

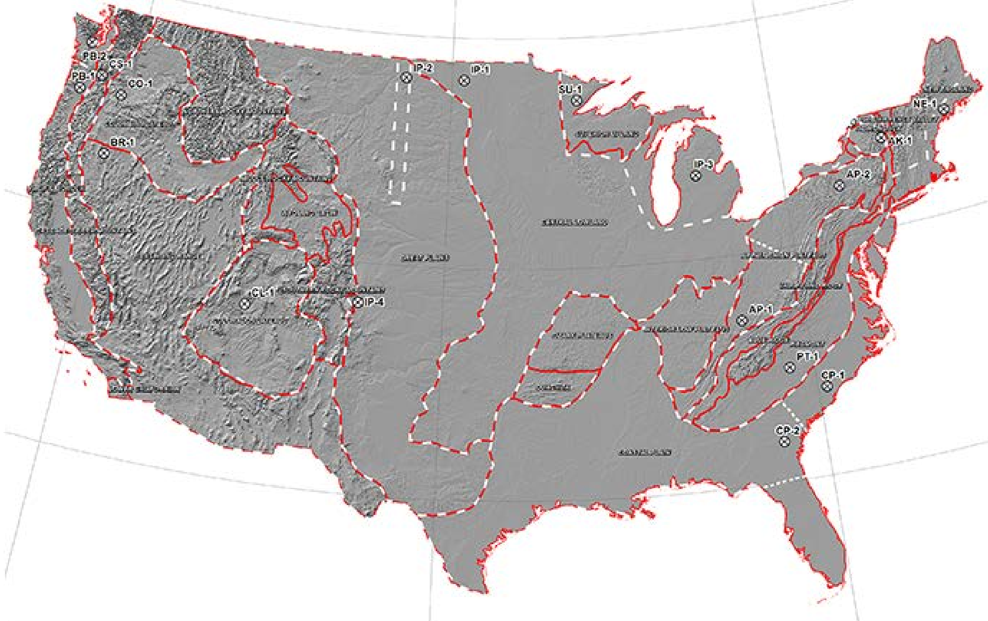
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from magnetotelluric data and are available from the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions these will all be different (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use a β factor of 1 or other technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

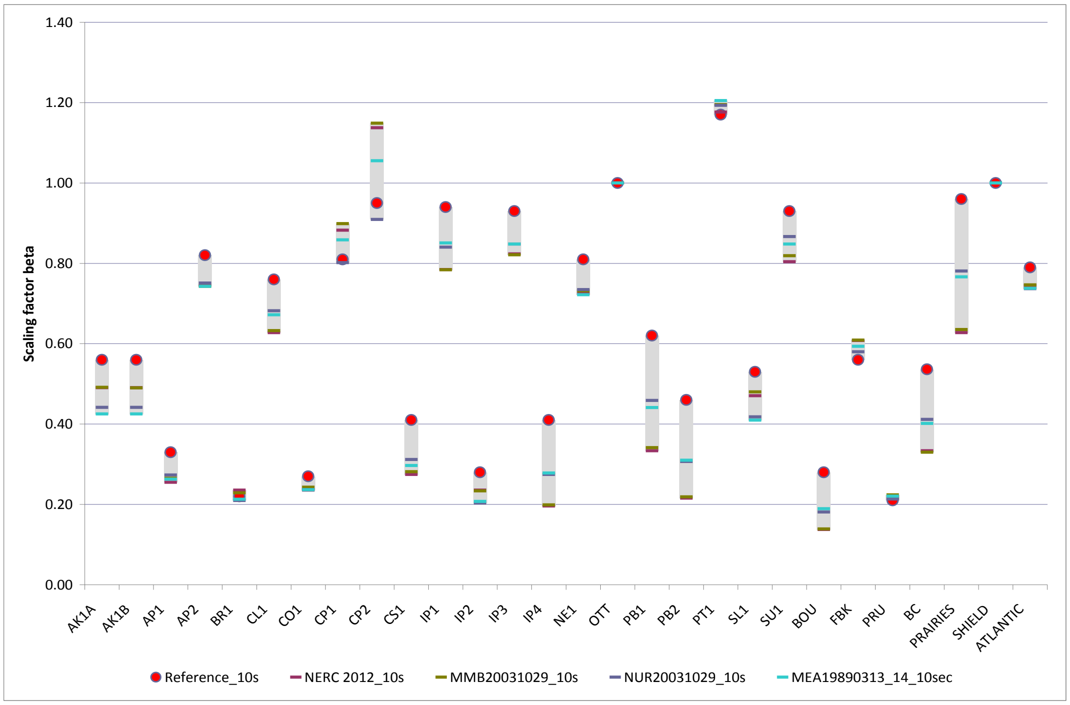


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles corresponds to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5V / km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity that the reference benchmark conductivity, and according to the conductivity factor β from Table II-2. Then:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
Draft: ~~April 21~~June 10, 2014

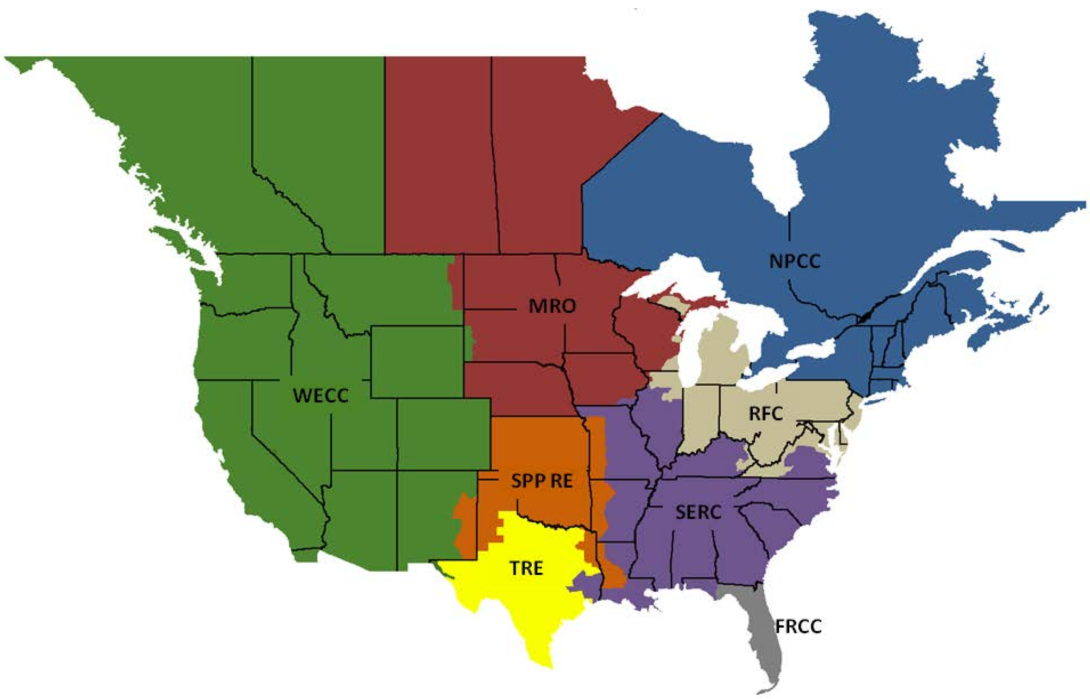
RELIABILITY | ACCOUNTABILITY

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide ~~uniform evaluation criteria~~a defined event for assessing system performance during a low probability~~ GMD event. It is to be used in conjunction with Reliability Standards that establish requirements for system modeling, vulnerability assessment, and mitigation planning.~~, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance ~~during~~for Geomagnetic Disturbance Events~~s~~. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. ~~The Stage 1 Standard,~~ EOP-010-1 – Geomagnetic Disturbance Operations is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increas~~ing~~ed amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously~~ and~~, but instead may take up to several seconds. ~~From a practical point of view, assuming~~It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous~~ is conservative~~.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic

activity. 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.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability ~~of occurrence of~~that the event ~~and~~will occur, as well as the impact or consequences of ~~the~~such an event. The benchmark event is composed of the following elements: ~~(~~1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; ~~(~~2) scaling factors to account for local geomagnetic latitude; ~~(~~3) scaling factors to account for local earth conductivity; and ~~(~~4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

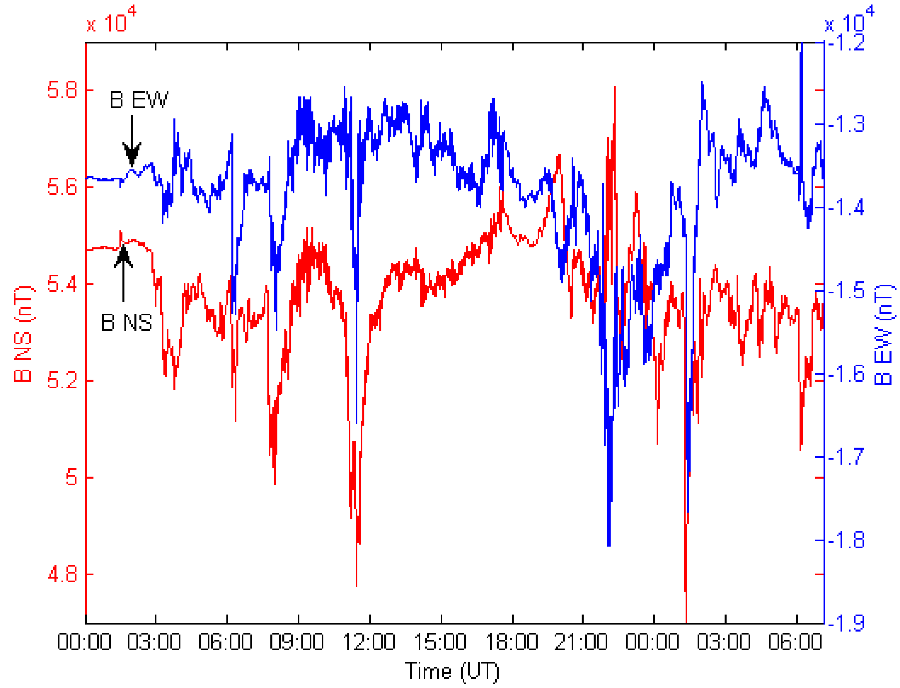
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \qquad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the “Halloween event” of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.



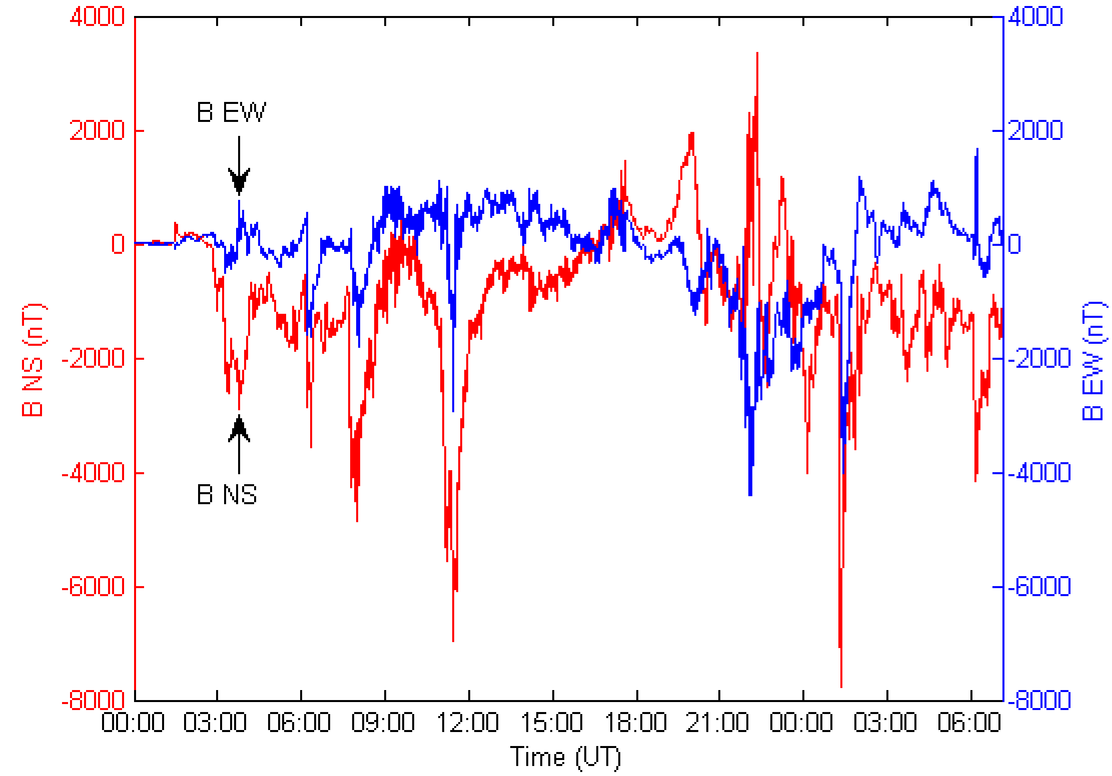
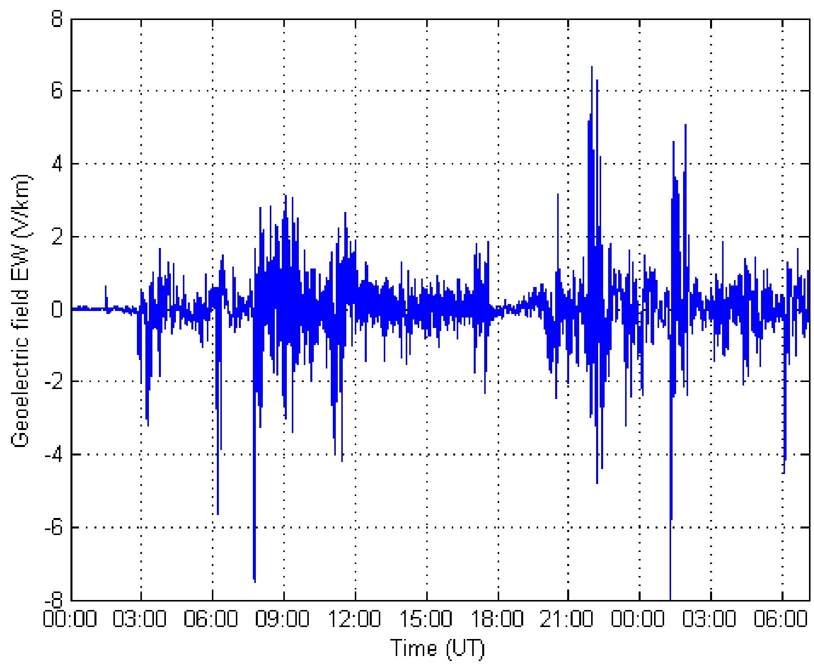


Figure 1: Benchmark Geomagnetic Field Waveshape

Red Bn (Northward), Blue Be (Eastward)



Referenced to pre-event quiet conditions

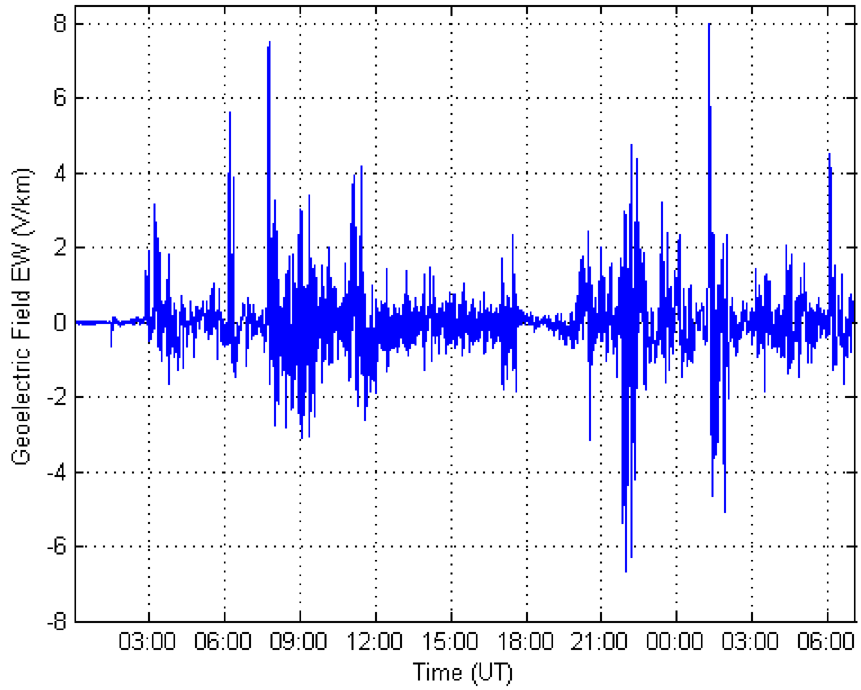
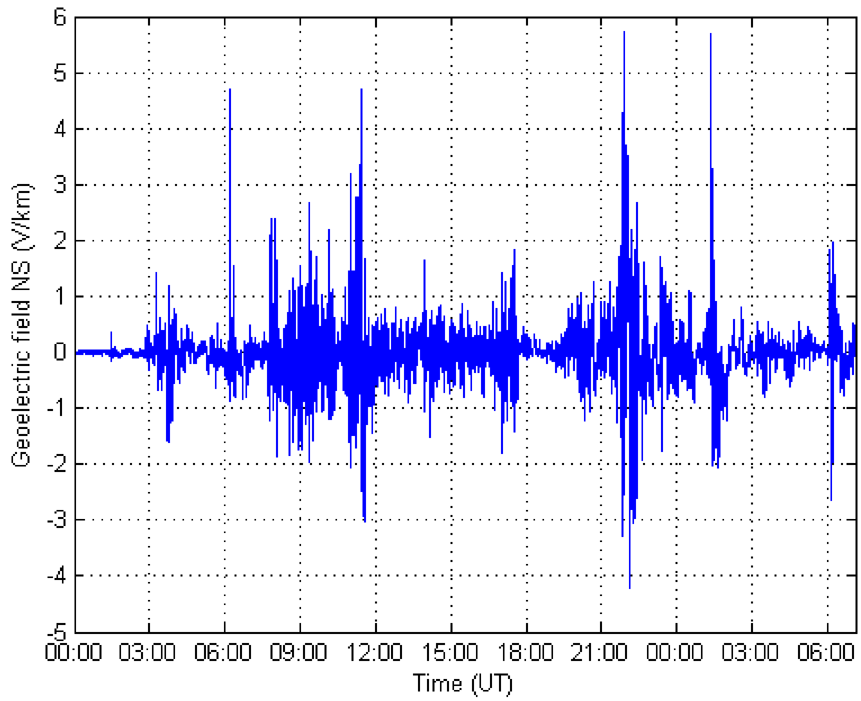


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)



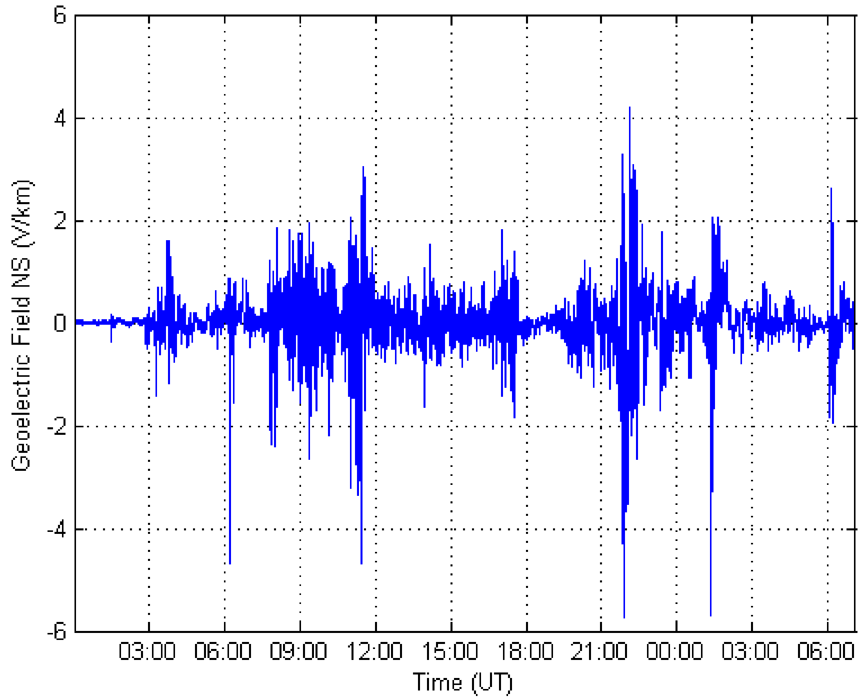


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of ~~pre-1980s~~ events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available ~~pre-~~for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. ~~It should be noted that the~~The error bars in such analysis are significant, ~~but~~however it ~~can be concluded~~is reasonable to conclude that statistically the March 1989 event is~~, statistically speaking,~~ likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity ~~conductivity~~ features that result~~s~~ in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that any one area is more likely to experience a localized enhanced geoelectric field.

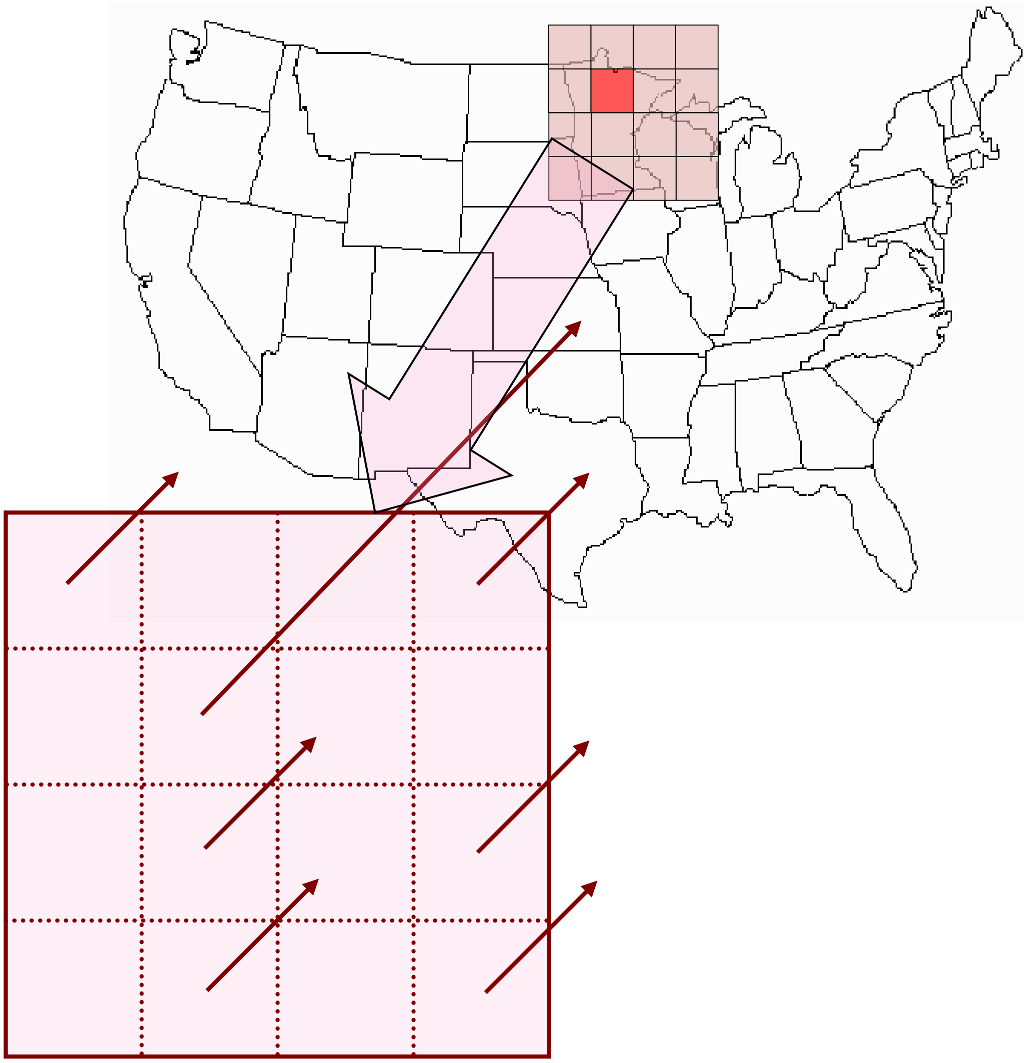


Figure I-1: Illustration of the ~~spatial scale~~Spatial Scale between ~~localized enhancements~~Localized Enhancements and ~~larger spatial scale amplitudes~~Larger Spatial Scale Amplitudes of ~~geoelectric field observed~~Geoelectric Field Observed during a ~~strong geomagnetic storm.~~ Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without ~~characterization of~~characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions ~~from~~when considering cascading failure and voltage collapse~~ points of view~~. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process ~~would involve~~involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

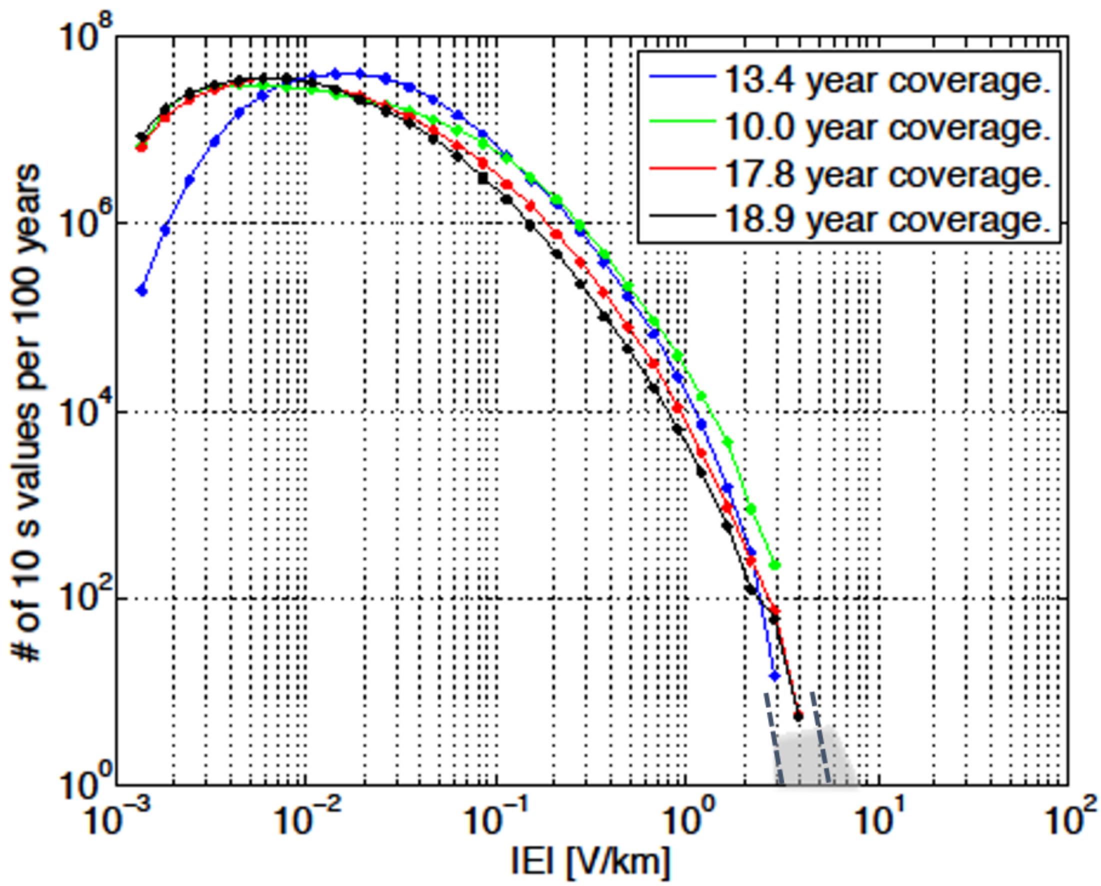


Figure I-2: Statistical ~~o~~Occurrence of ~~spatially averaged geoelectric field amplitudes~~Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. Dashed lines represent the values predicted with extreme value analysis. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geo-electric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

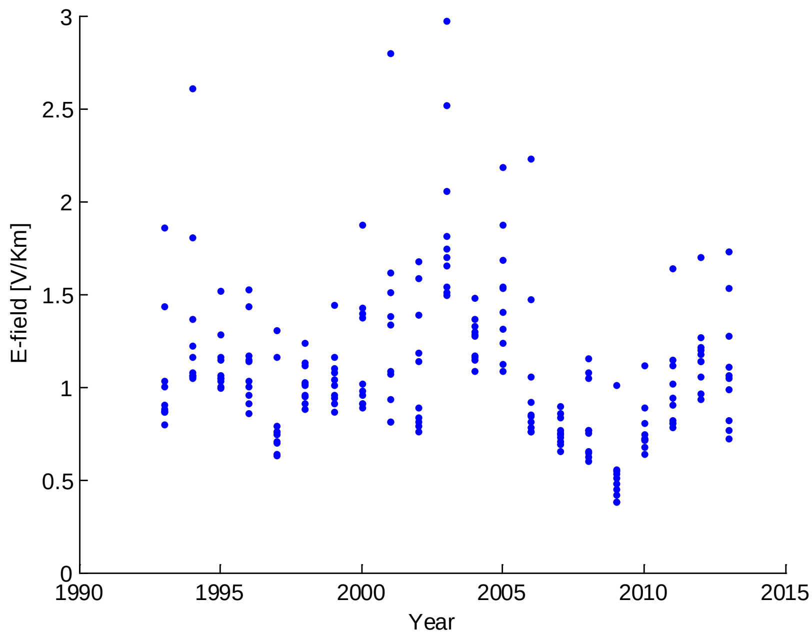


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if we were to obtain repeated samples, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

			100 Year Return Level		
Statistical Method	Estimated Parameters	Hypothesis Testing	Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\cancel{\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)}$ $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\cancel{\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)}$ $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\cancel{\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)} \quad \mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The ~~upshot~~benefit is an increase in the mean return level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low ~~a threshold~~ will likely lead to bias. On the other hand, ~~too high~~ a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\cancel{\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)} \quad \sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistical significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis shows that the geoelectric field amplitude of 8 V/km for the benchmark is conservative for a 100-year return level and it includes an implicit 25 percent ~~safety~~engineering margin.

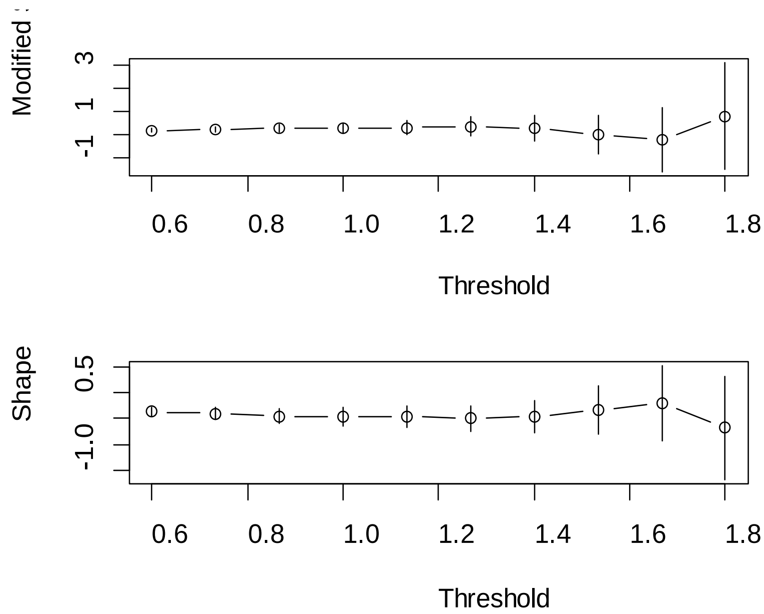


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

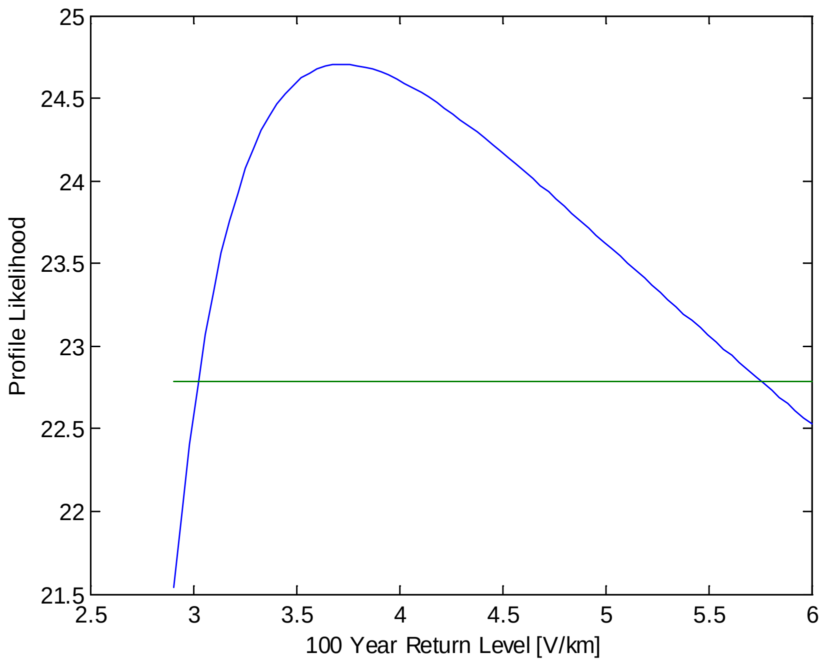


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network ~~was~~is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

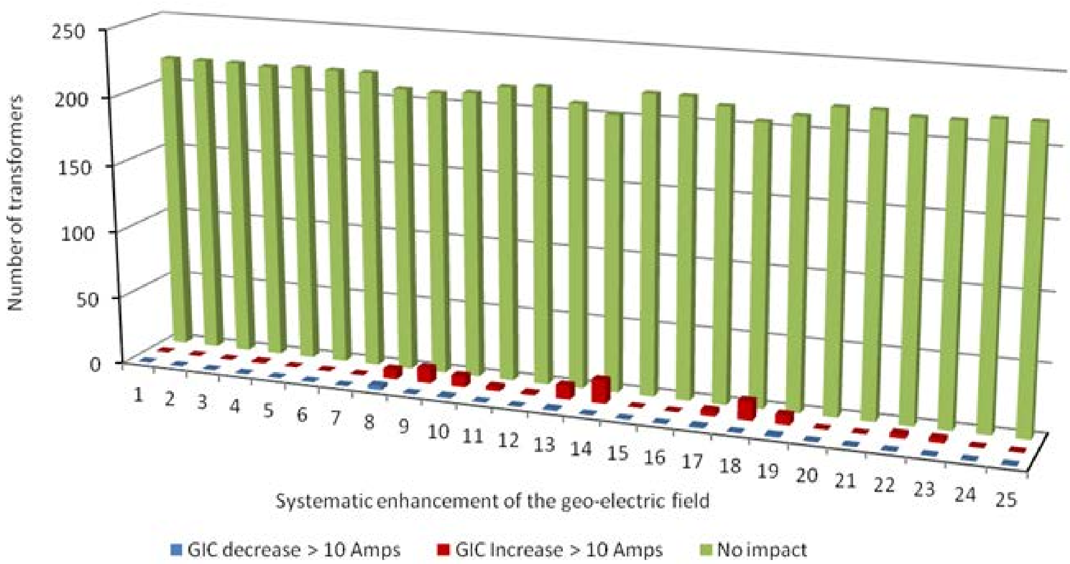


Figure I-6: Number of Transformers ~~That See~~that see a 10 A/phase Change in GIC ~~Due To~~due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

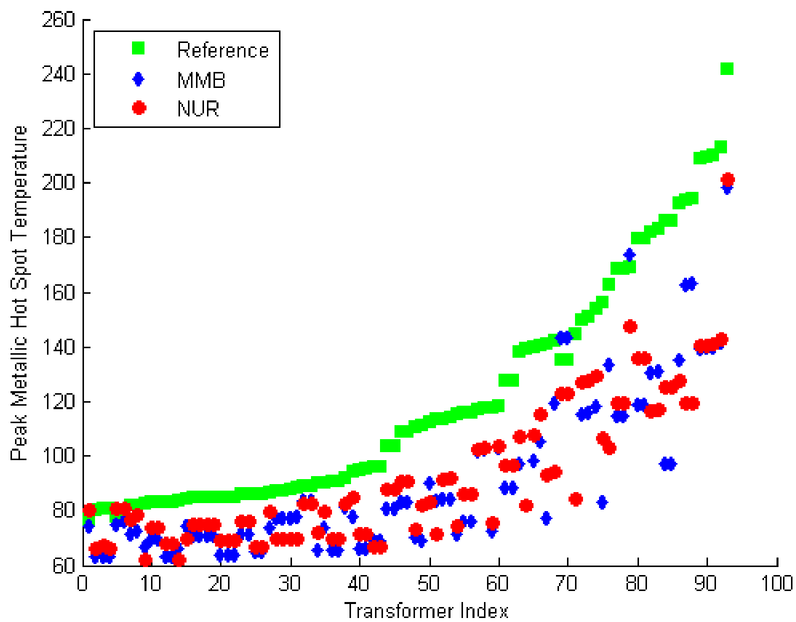


Figure I-7: Calculated ~~peak metallic hot spot temperature~~Peak Metallic Hot Spot Temperature for ~~all transformers~~All Transformers in a ~~test system~~Test System with a ~~temperature increase~~Temperature Increase of ~~more than~~More Than 20°C for ~~d~~Different GMD ~~events scaled~~Events Scaled to the ~~same peak geoelectric field~~Same Peak Geoelectric Field

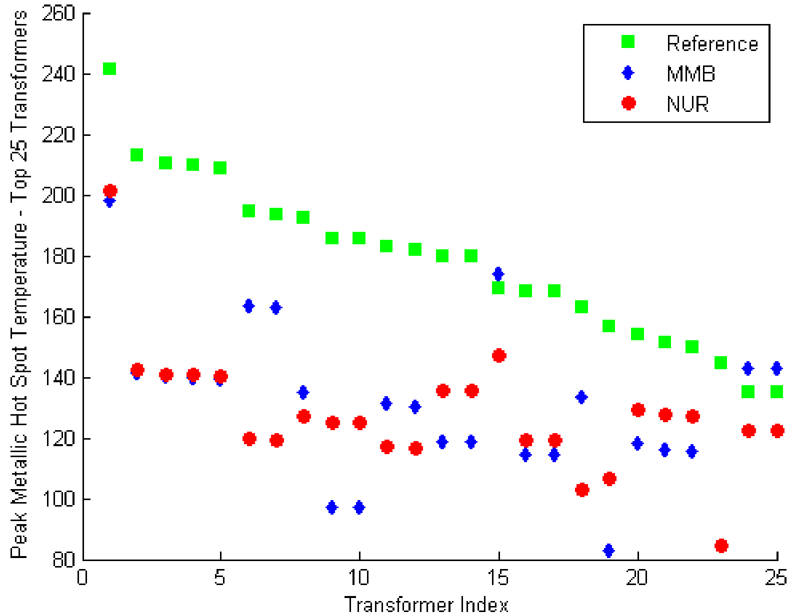


Figure I-8: Calculated ~~peak metallic hot spot temperature~~Peak Metallic Hot Spot Temperature for the ~~t~~Top 25 ~~t~~Transformers in a ~~test system~~Test System for ~~d~~Different GMD ~~events scaled~~Events Scaled to the ~~same peak geoelectric field~~Same Peak Geoelectric Field

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take in consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** ~~provides a~~summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\cancel{\alpha = 0.001 \cdot e^{(0.115 \cdot L)}} \quad \alpha = 0.001 \cdot e^{(0.115 \cdot L)}$$

(II.1)

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

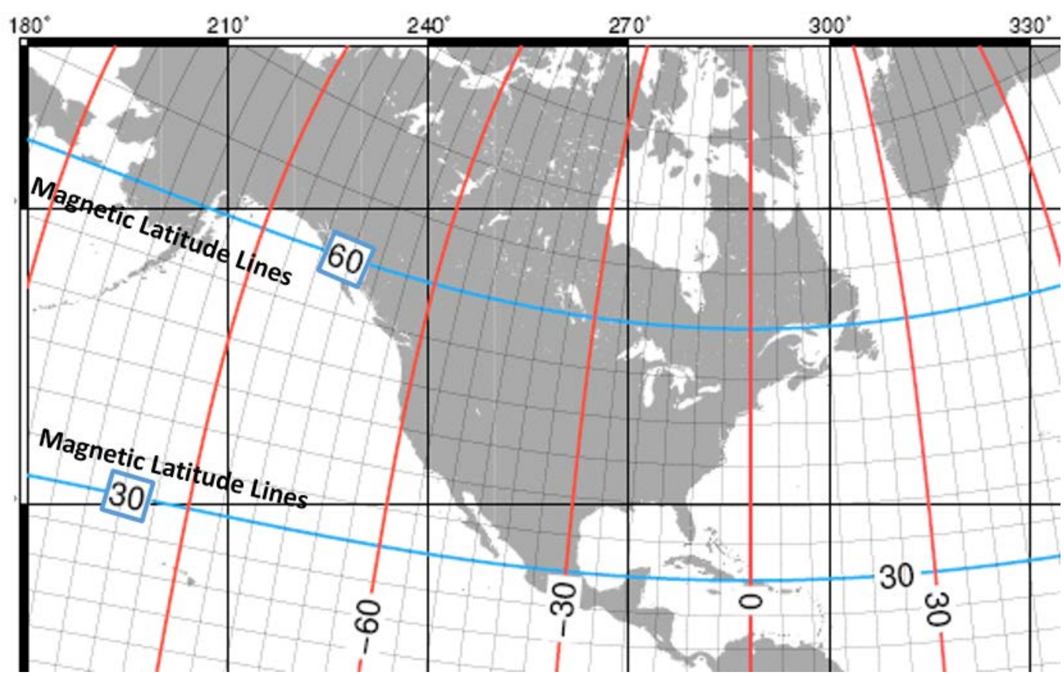


Figure II-1: Geomagnetic Latitude Lines in North America

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[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is ~~with respect~~in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
~~55~~54	0.~~6~~5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \tag{II.2}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

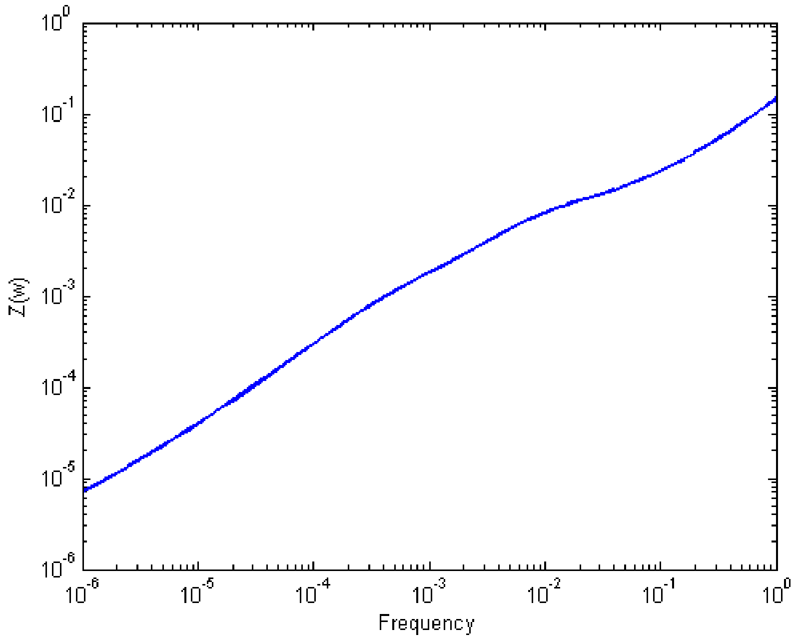


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

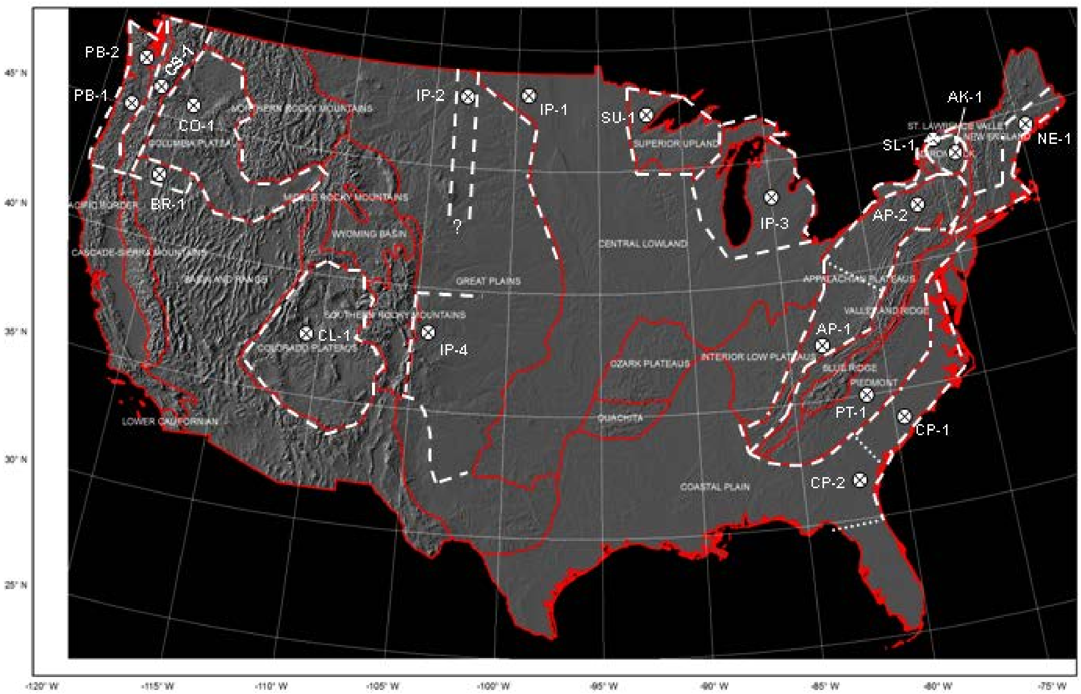
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States ~~is~~are from magnetotelluric data and ~~is~~are available from the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions these will all be different (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and ~~comprise~~consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second ~~geomagnetic field~~ recordings for these geomagnetic field time series.

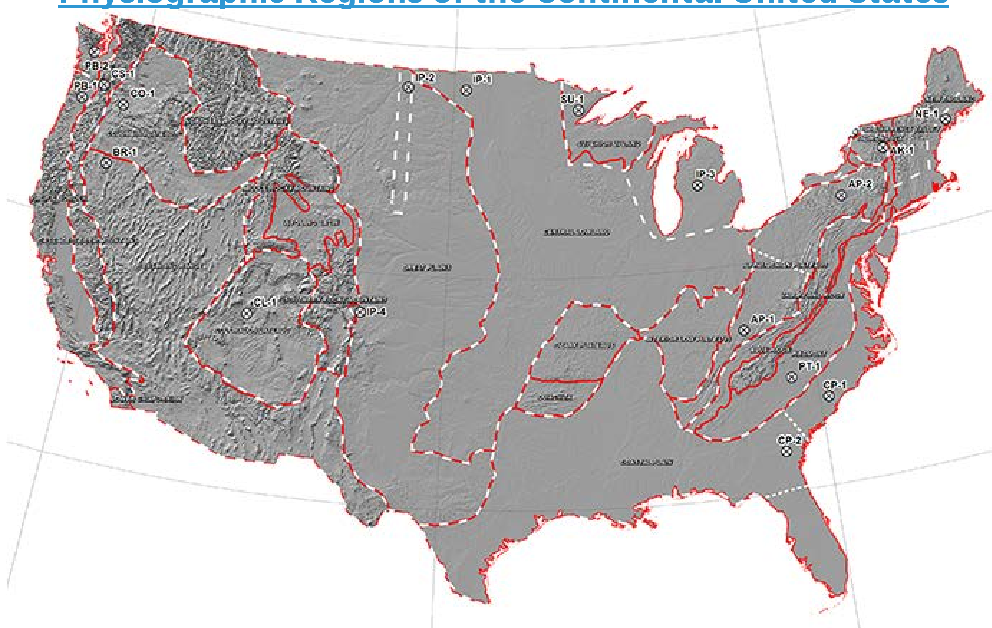
- If a utility has technically-sound earth models for its service territory ~~of~~and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

Location of 1D Earth Resistivity Models with respect to Physiographic Regions of the USA



- When a ground conductivity model is not available the planning entity should use a β factor of 1 or other technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62

PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

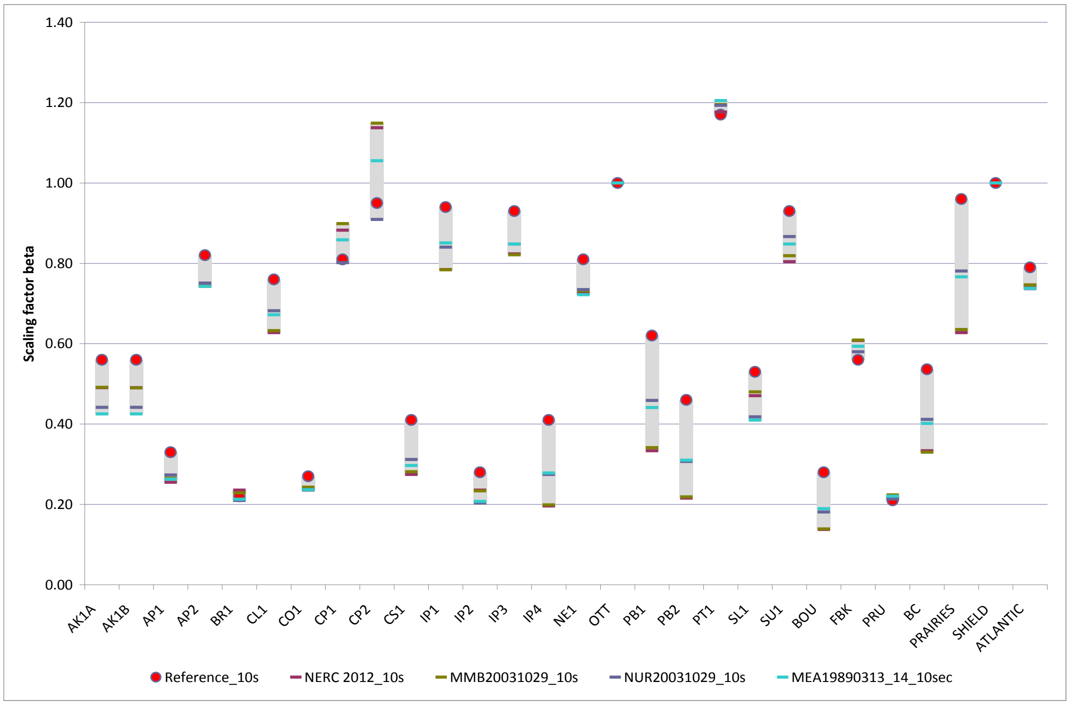


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles corresponds to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α ~~from Table~~calculated using II~~-~~.1 is 0.56~~2~~; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V / km$$
$$\alpha = 0.562$$
$$\beta = 1$$
$$Epeak = 8 \times 0.562 \times 1 = 4.5 \text{ V/km}$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α ~~from Table~~calculated using II~~-~~.1 is 0.56~~2~~; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity that the reference benchmark conductivity, and according to the conductivity factor β from Table II-2. Then:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2 V / km$$

$$\alpha = 0.562$$

$$\beta = 1.17$$

$$Epeak = 8 \times 0.562 \times 1.17 = 5.3 \text{ V/km}$$

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Transformer Thermal Impact Assessment White Paper (Draft)

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

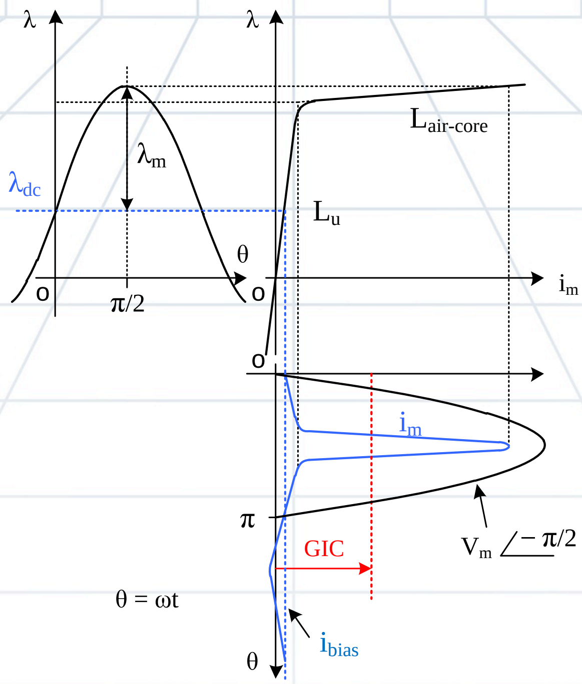

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation, and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.
- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2]

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \tag{1}$$

where,

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

There are two different ways to carry out a detailed thermal impact screening:

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers and limited information is available regarding the assumptions used to generate these curves, in particular the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. 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.

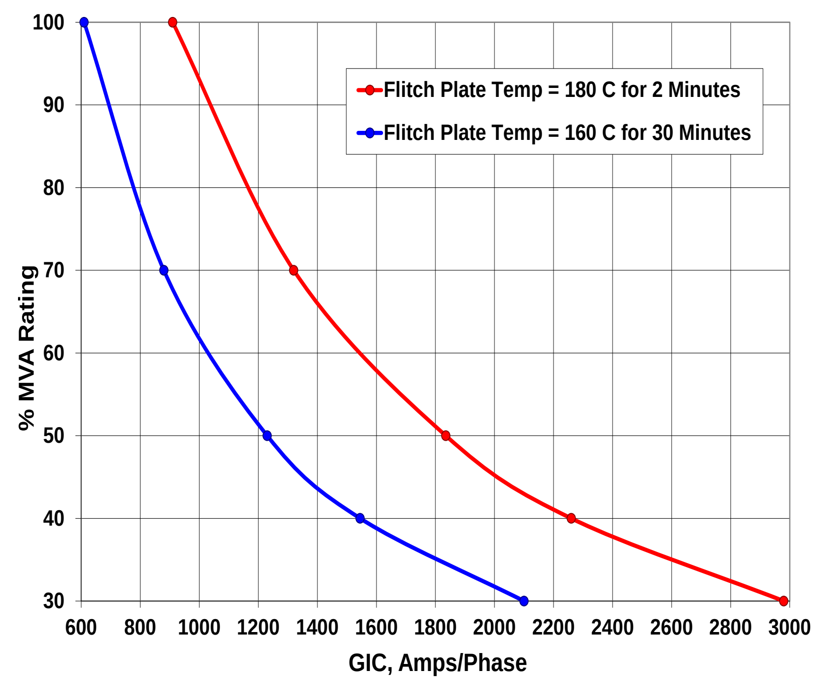

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system) and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std. C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

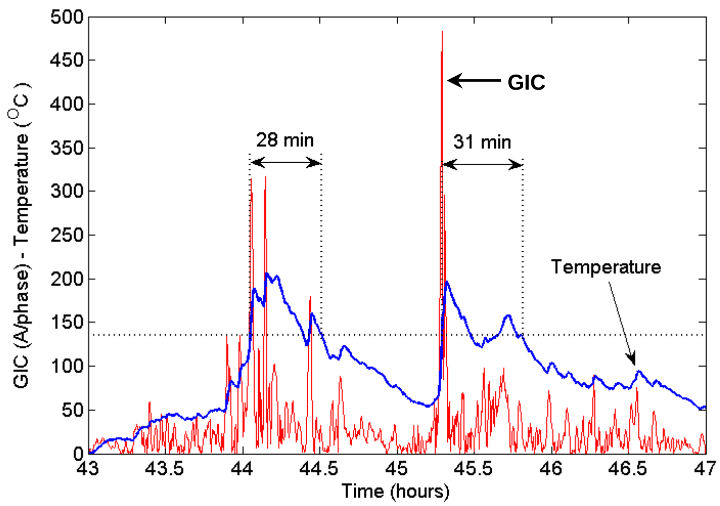

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;

[1] Technical details of this methodology can be found in [4].

2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase/V/km) for any value of E_E (t) and E_N(t) can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \tag{2}$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km.

The geoelectric field time series E_N(t) and E_E(t) is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator) the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2] and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already taken into account by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore,

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

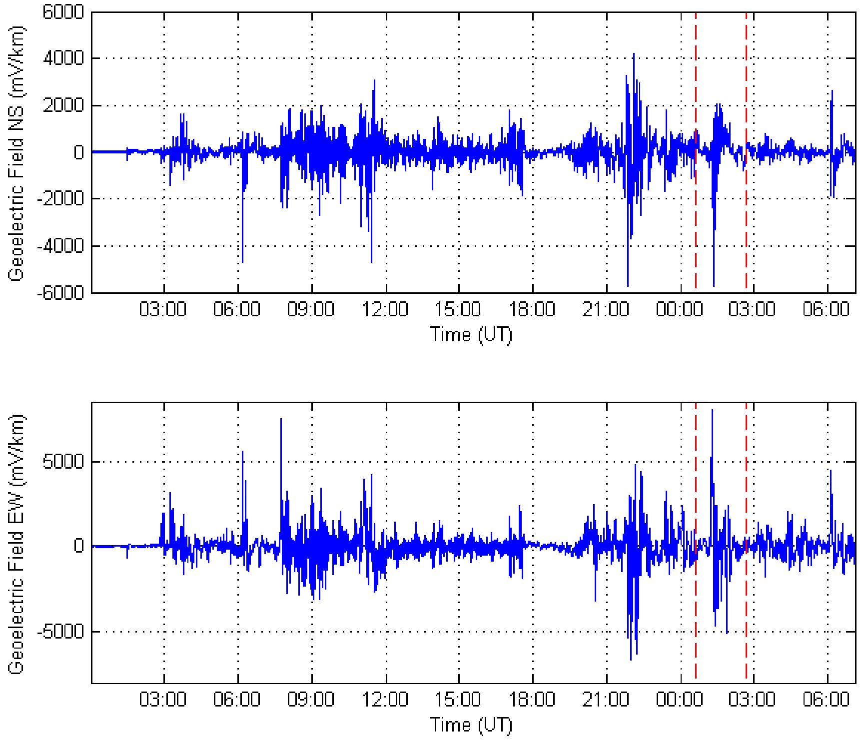

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

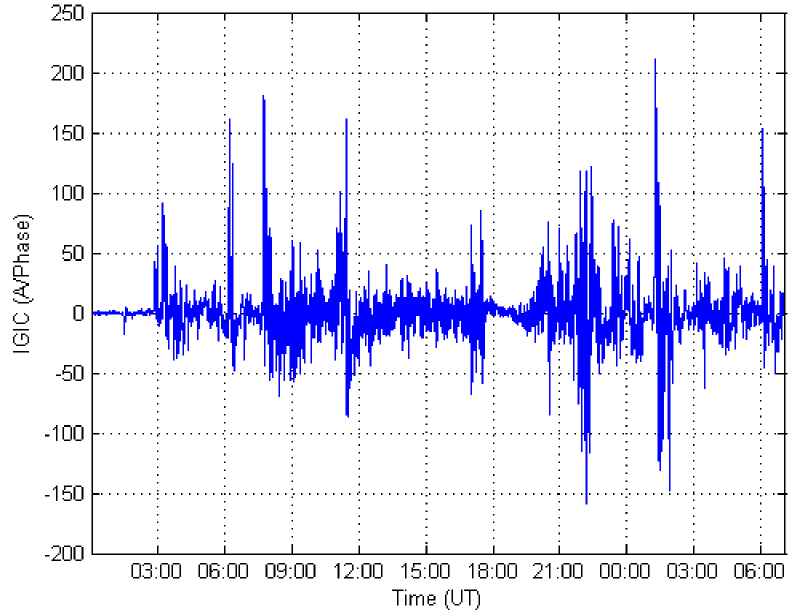

Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

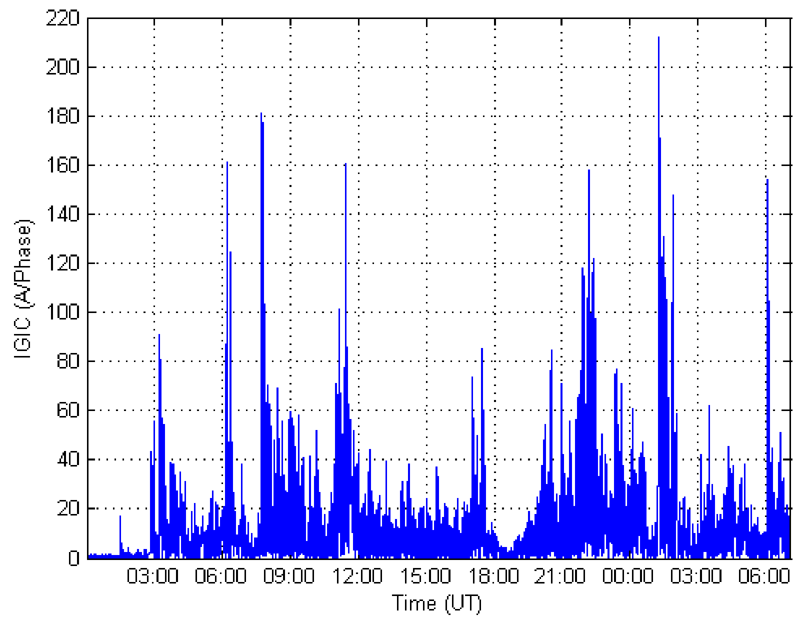

Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating the thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

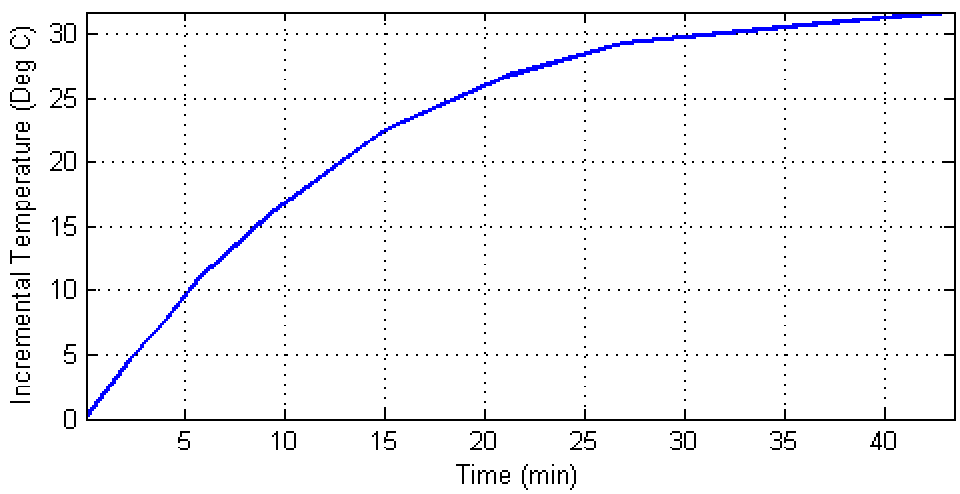

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] The heating of the bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

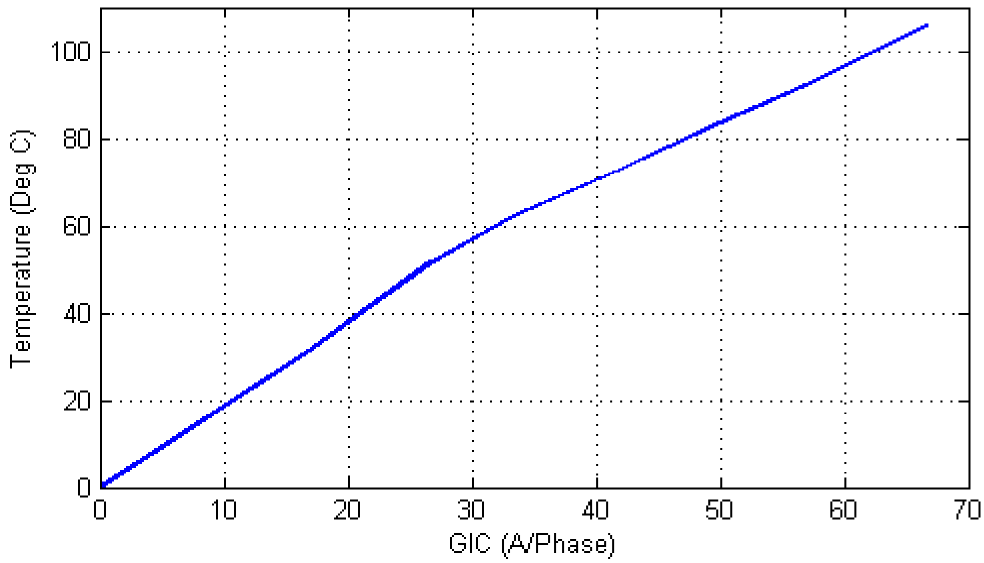

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

In order to obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 9 shows the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 10** shows a close-up of the peak transformer temperatures calculated in this example.

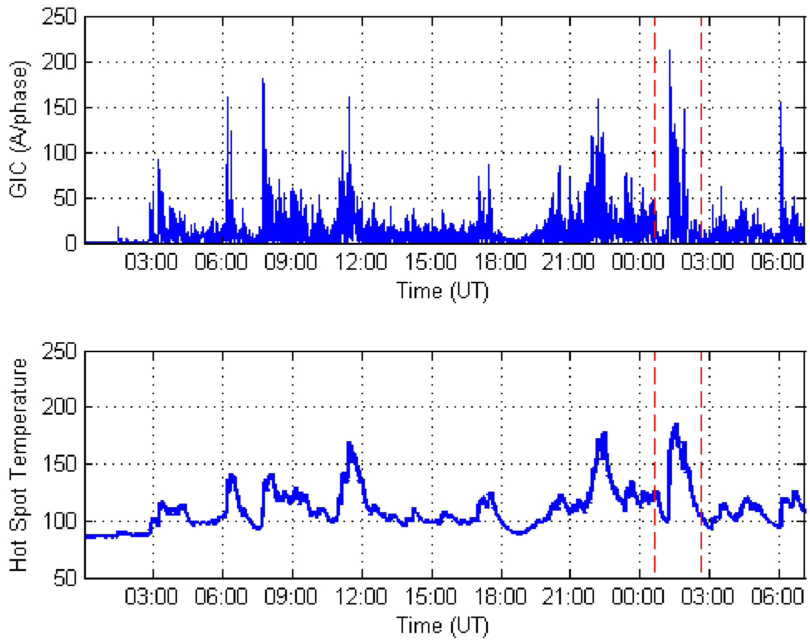

Figure 9: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

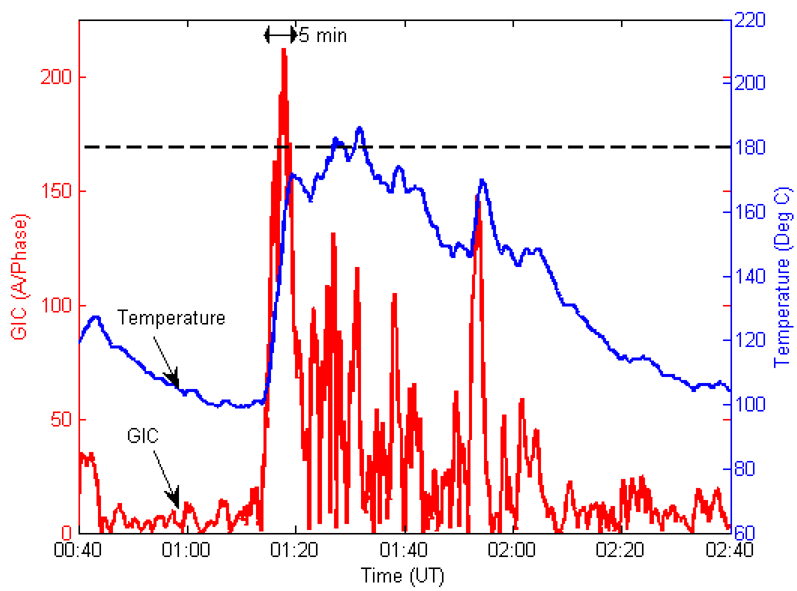

Figure 10: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example the IEEE Std. C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins as well as transformer age and condition. **Figure 10** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 11**).

If a conservative threshold of 160°C were to be used to take into account the age and condition of the transformer, then the full load limits would exceeded for approximately 22 minutes.

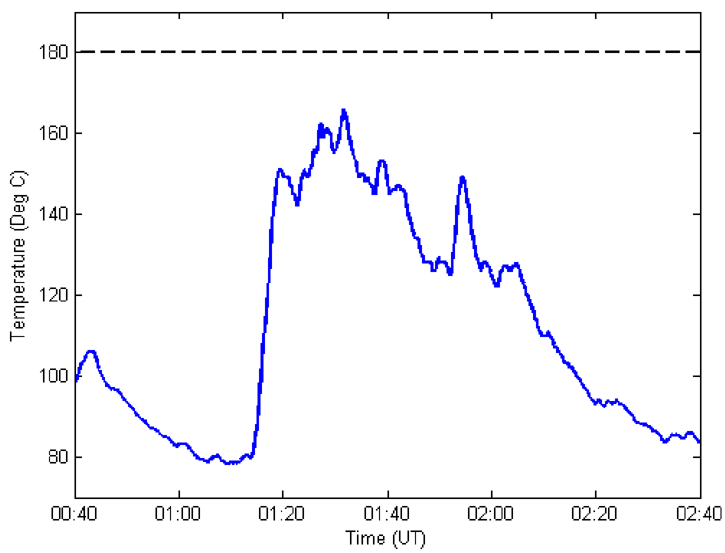

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 12**. To be consistent with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 8** and **9**, and the simplified loading curve shown in **Figure 14** (calculated using formulas from IEEE Std. C57.91).

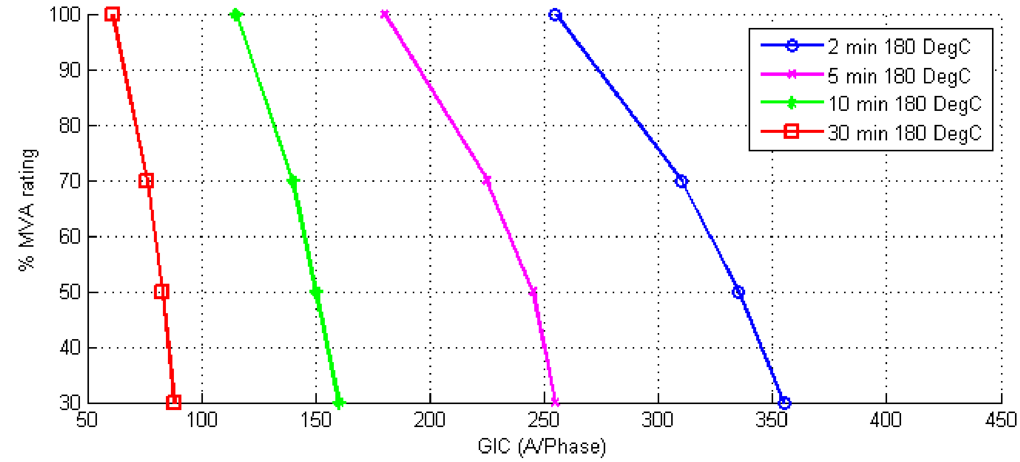

Figure 12: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

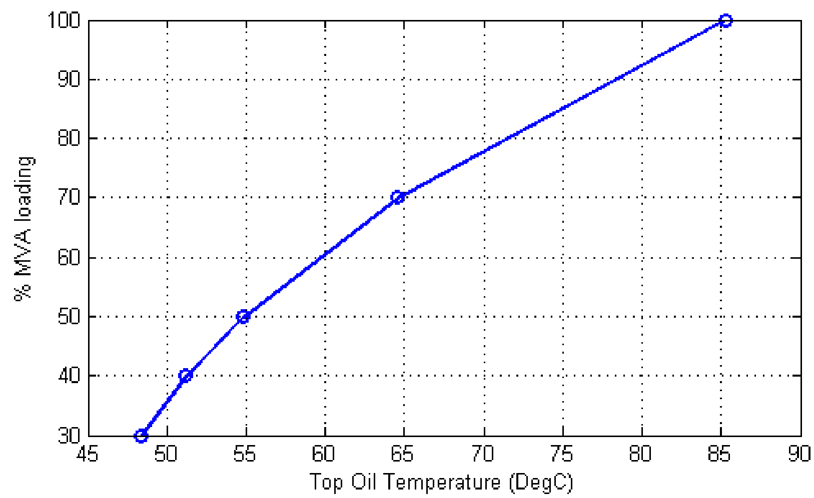

Figure 13: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve then the transformer is within its capability.

To use these curves it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 14** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 12**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 15**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

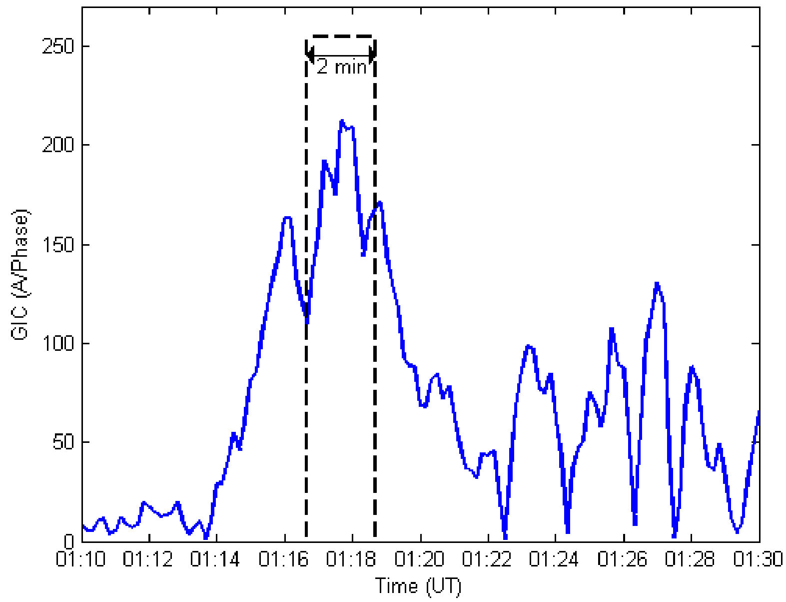

Figure 14: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

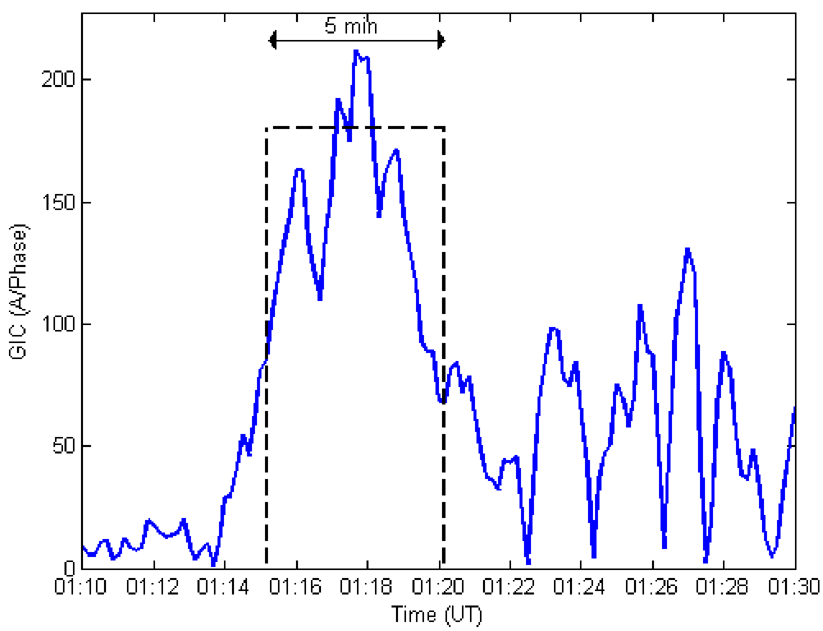

Figure 15: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), allowances have to be made in terms of prior hot spot heating. From these considerations it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 12** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 16**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were to be used to take into account the age and condition of the transformer, then a new set of capability curves would be required.

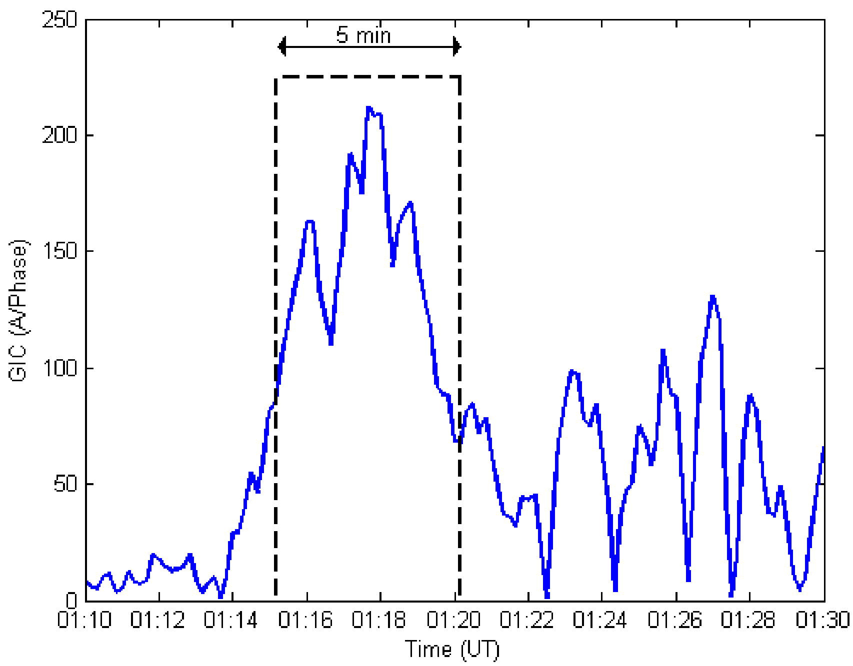

Figure 16: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

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Transformer Thermal Impact Assessment White Paper (Draft)

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance ~~during~~for Geomagnetic ~~Disturbances~~Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. ~~The Stage 1 Standard,~~ EOP-010-1 – Geomagnetic Disturbance Operations is pending at FERC in Docket No. RM14-1-000.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC~~),~~) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

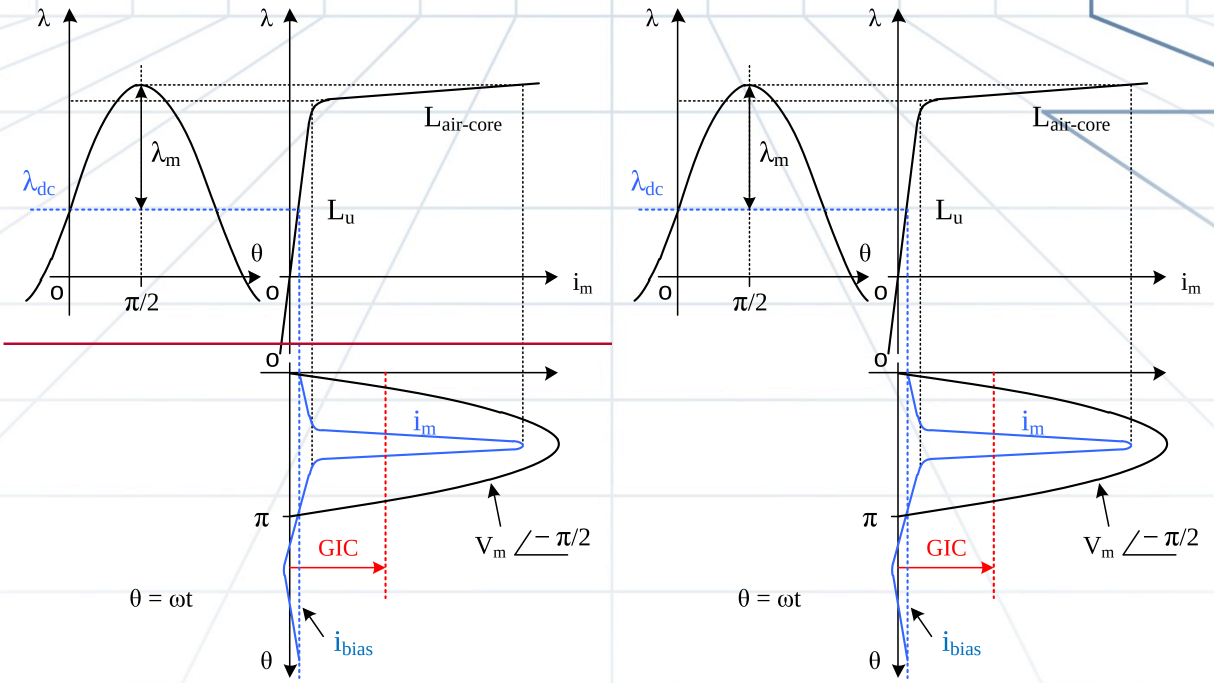

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation, and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.
- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
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$$\cancel{I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H} \; \underline{I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H} \qquad (1)$$

where,

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
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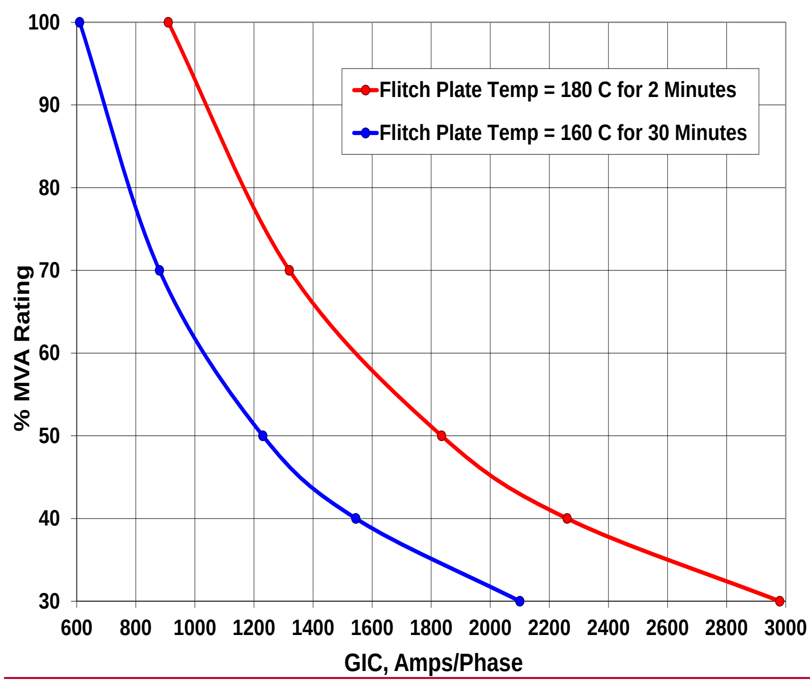


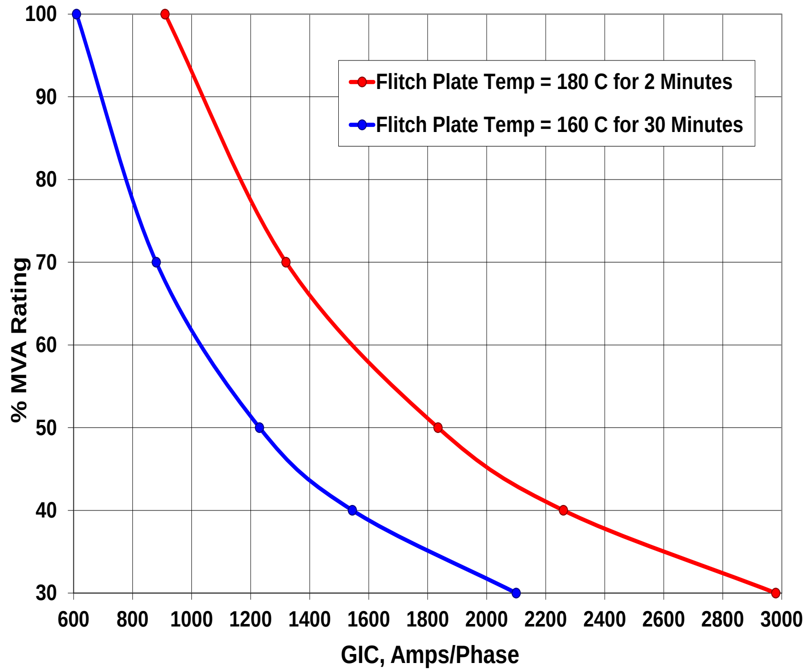


Figure 2: Sample GIC ~~manufacturer capability curve~~Manufacturer Capability Curve of a ~~large single-phase transformer design~~Large Single-Phase Transformer Design using the Flitch ~~plate temperature criteria~~Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system) and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. ~~Default~~Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std. C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

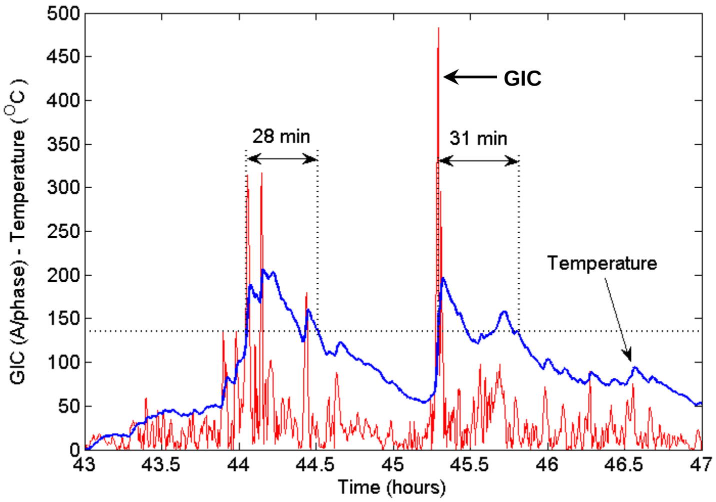


Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC ~~w~~Waveshape for a ~~t~~Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform ~~E~~eastward geoelectric field of 1 V/km (GIC_E) while the ~~N~~northward geoelectric field is zero. Similarly, GIC_N can be obtained ~~when~~for a uniform ~~N~~northward geoelectric field of 1 V/km while the ~~E~~eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase/V/km) for any value of E_E (t) and E_N(t) can be calculated using (2) [2].

$$\cancel{GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\}}$$

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \tag{2}$$

where

$$\cancel{|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)}} \; |E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\cancel{\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right)} \; \varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a ~~N~~northward geoelectric field of 1 V/km and GIC_E is the effective GIC due to an ~~E~~eastward geoelectric field of 1 V/km.

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude ~~factor α is applied[2]. Applying (2~~scaling factor α is applied[3]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[4]. Alternatively the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already taken into account by the use of the appropriate earth model.

~~[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator) the lower the amplitude of the geomagnetic field.~~

[3] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator) the lower the amplitude of the geomagnetic field.

[4] The conductivity scaling factor β is described in [2] and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

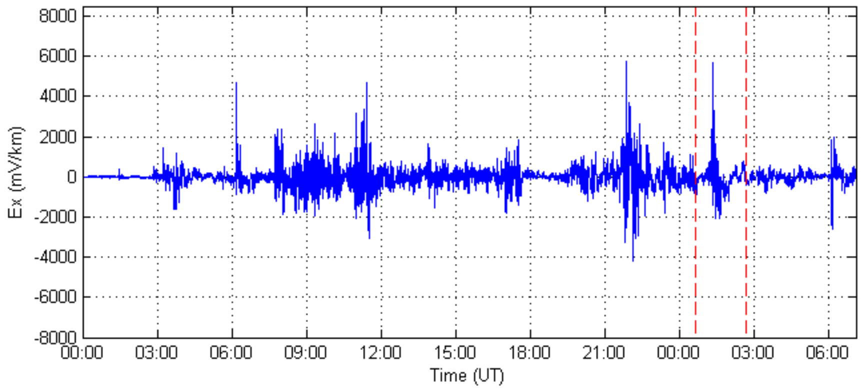
Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -~~6A~~20 A/phase if E_N=0, E_E=1 V/km and GIC_N = ~~9.6A~~26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore,

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.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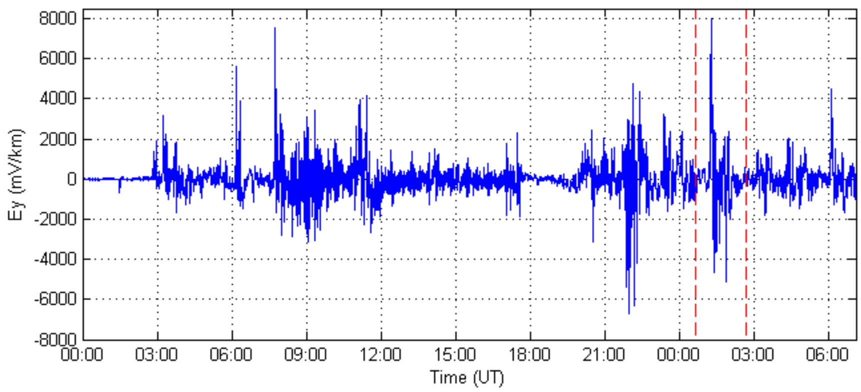
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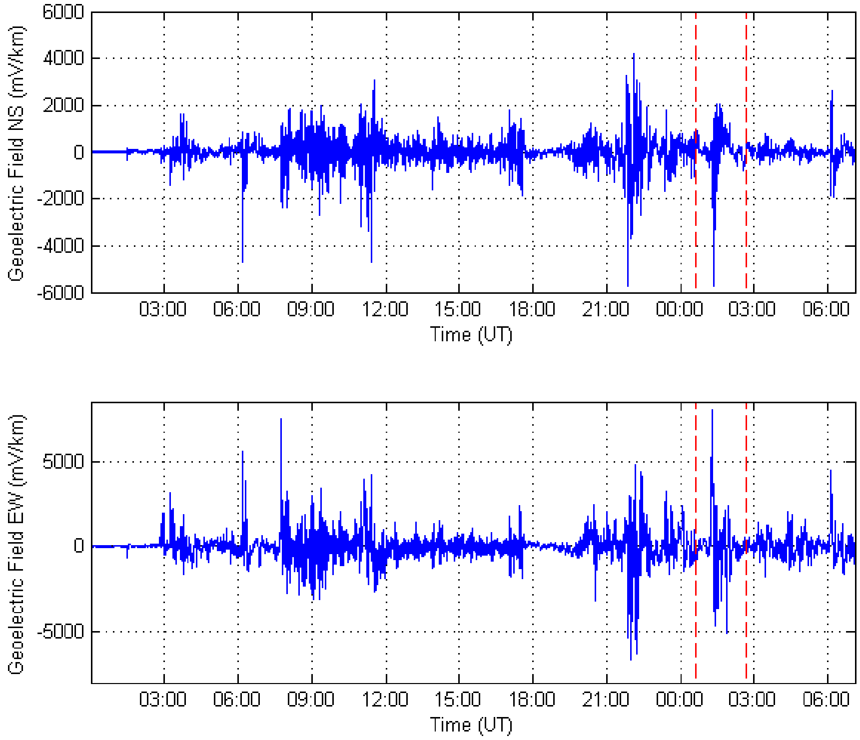


Figure 4: Calculated ~~geoelectric field~~Geoelectric Field $E_N(t)$ and $E_E(t)$ ~~a~~Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model~~)~~
). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

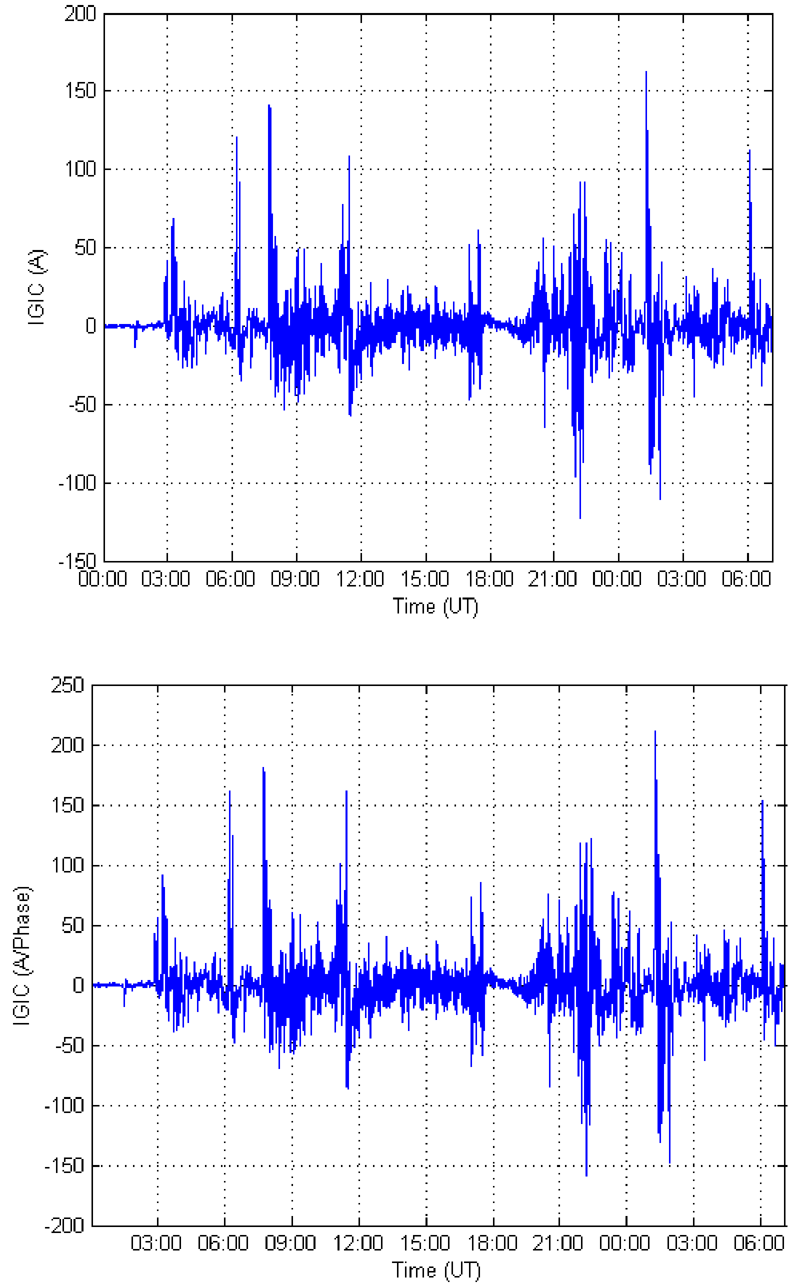
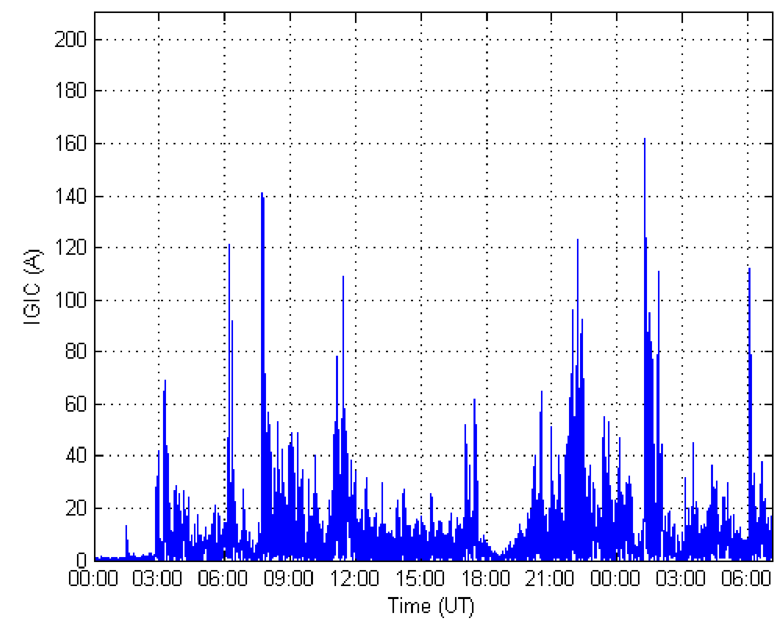


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)



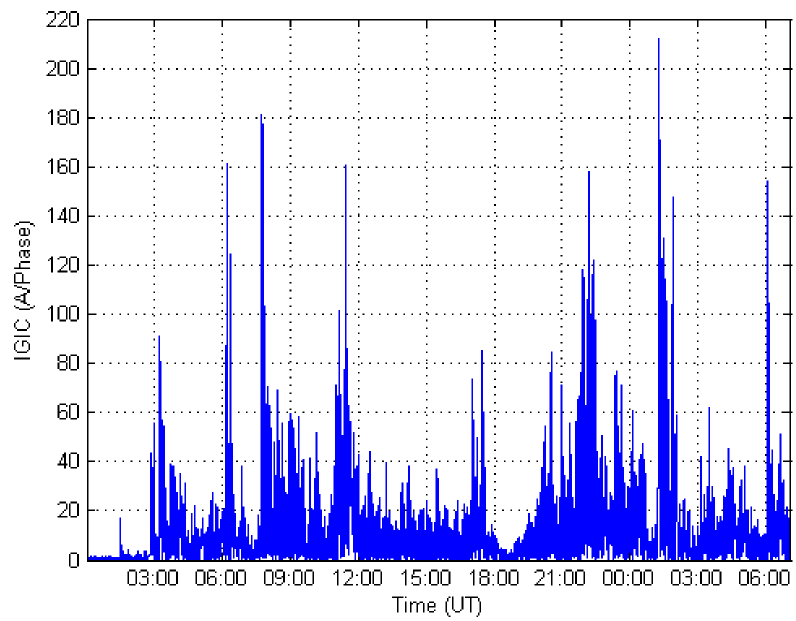


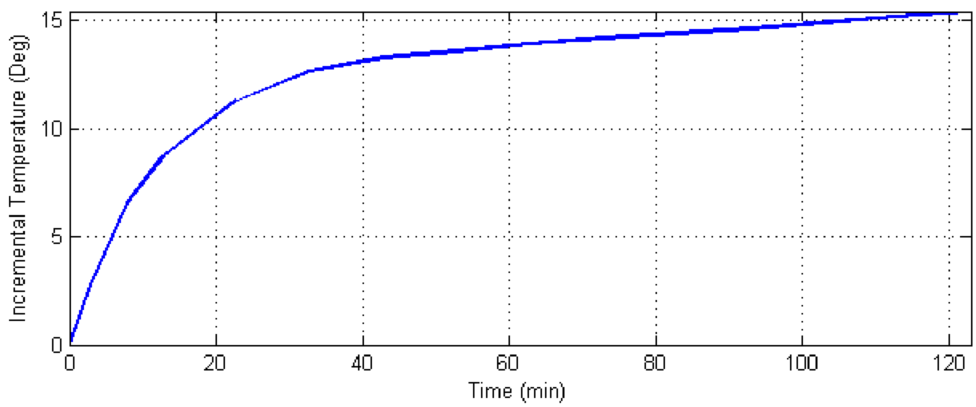
Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) ~~using manufacturer's capability curves, and 2)~~ calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: ~~Using~~Calculating the thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: ~~(a~~1) measurements; ~~(b~~2) manufacturer's calculations; or ~~(c~~3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [~~4~~6] that will be used in this example. **Figure 8** shows the ~~estimated~~measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[5] ~~The asymptotic response in **Figure 8** is extrapolated linearly from relatively low magnitude dc measurements. This is a conservative approximation for illustration purposes. In the Fingrid transformer tests reported in 2002 [6], the measured maximum value of the asymptotic response of the inside of the yoke clamp (highest hot spot temperature) is 15% lower than the value obtained using linear extrapolation. The linear extrapolation results in a calculated temperature peak 9% higher than the measured asymptotic behavior when the GIC(t) time series in **Figure 6** is used.~~



[5] The heating of the bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

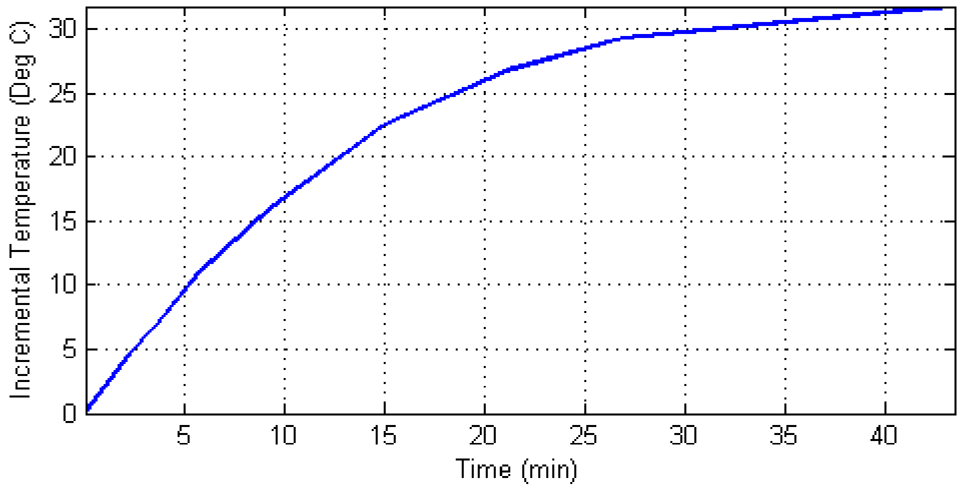
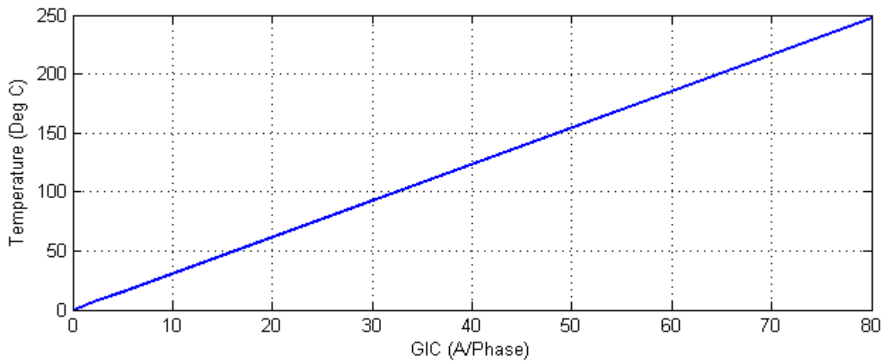


Figure 7: Thermal Step Response to a ~~5 A/ phase~~ 16.67 Amperes per Phase dc Step ~~[3]~~

Metallic hot spot heating.



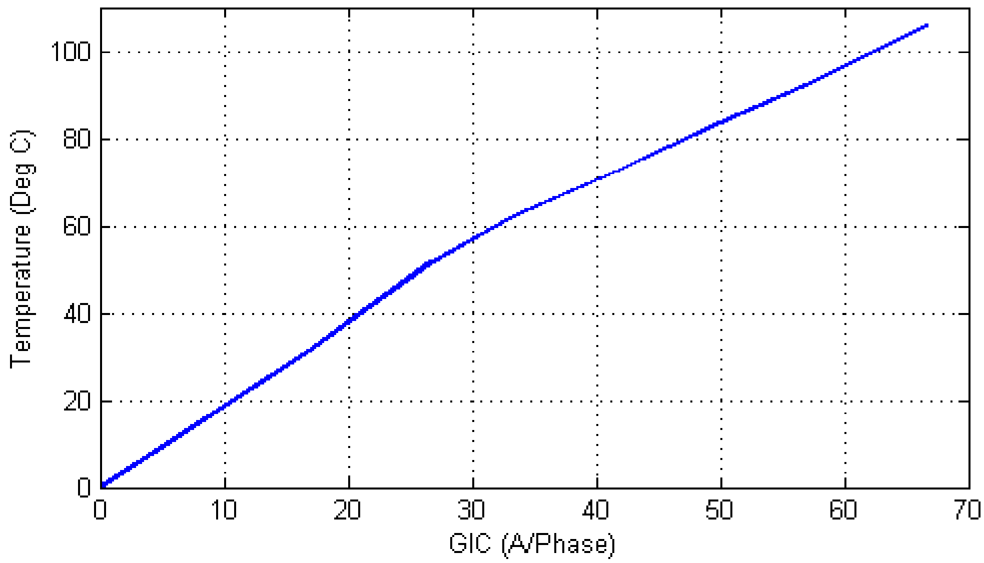
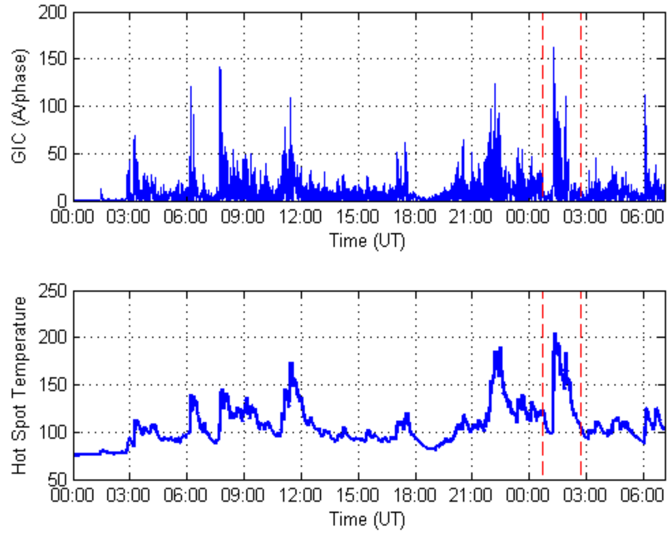


Figure 8: Asymptotic Thermal Step Response ~~[4]~~
Metallic hot spot heating.

In order to obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 9 shows the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 10** shows a close-up of the peak transformer temperatures calculated in this example.



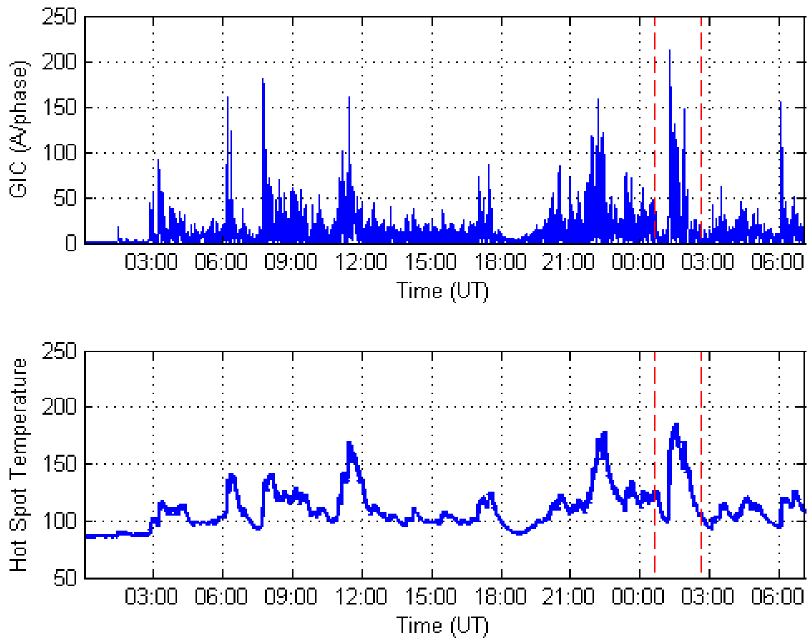


Figure 9: Magnitude of GIC(t) and ~~metallic hot spot temperature~~Metallic Hot Spot Temperature θ(t) ~~assuming full load oil temperature~~Assuming Full Load Oil Temperature of ~~75~~85.3°C (~~30~~40°C ambient~~)~~). Dashed lines approximately show the close-up area for subsequent Figures.

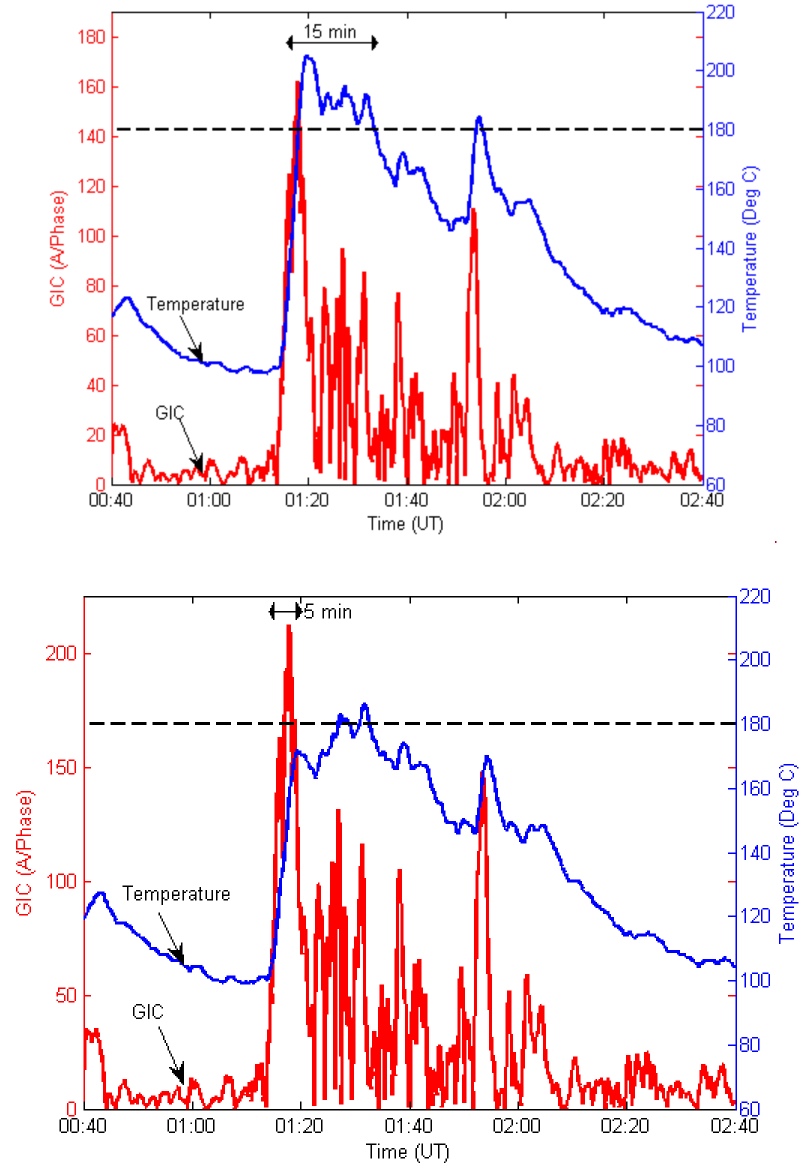


Figure 10: Close-up of Metallic ~~hot spot temperature~~ Hot Spot Temperature Assuming a Full Load

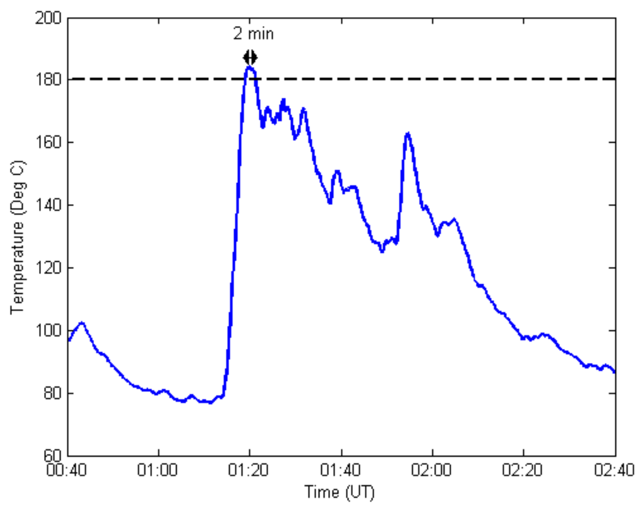
(Blue trace is θ(t~~) assuming a full load (blue trace)~~). Red trace is GIC(t~~)~~))

In this example the IEEE Std. C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded~~ for 3 minutes (as opposed to 30 minutes for emergency overloading).~~ . Peak temperature is ~~204~~186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins as well as transformer age and condition. **Figure 10** shows that 180°C will be exceeded for ~~15~~5 minutes.

At ~~70~~75% loading, the initial temperature is ~~54.5~~64.6 °C rather than ~~75~~85.3 °C and the hot spot temperature peak is ~~183~~165°C~~. In this case~~, well below the 180°C threshold ~~is~~(see **Figure 11**).

If a conservative threshold of 160°C were to be used to take into account the age and condition of the transformer, then the full load limits would exceeded for ~~2~~approximately 22 minutes~~ (see **Figure 11**)~~.



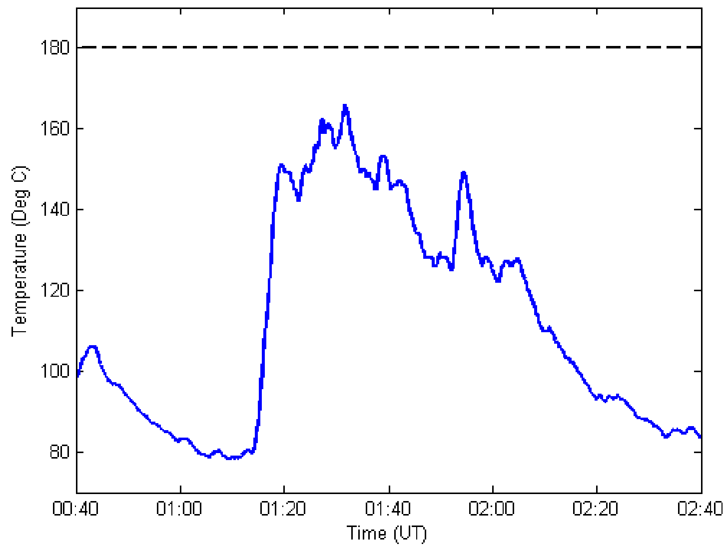
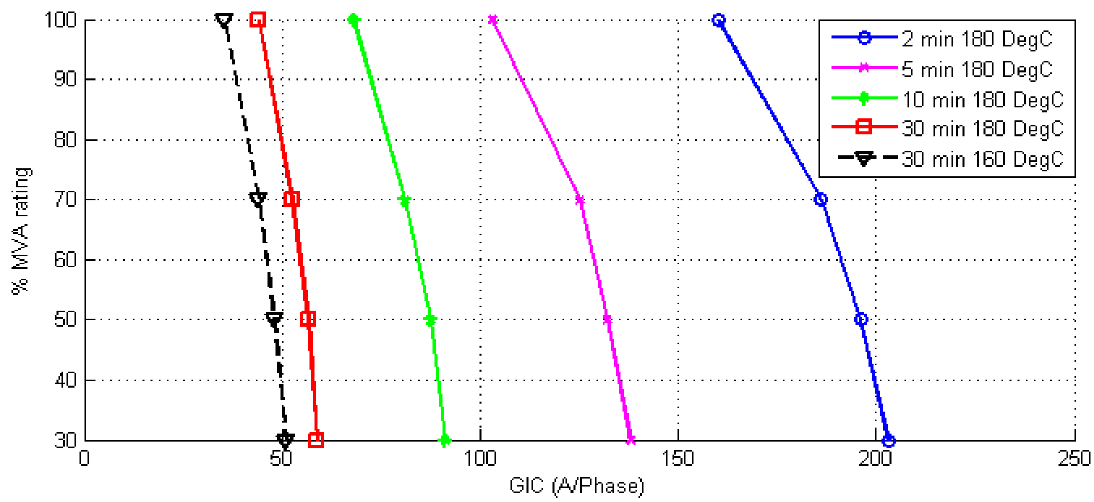


Figure 11: Close-up of Metallic ~~hot spot temperature assuming a 70 % load~~ Hot Spot Temperature Assuming a 75 % Load
(Oil temperature of ~~54~~64.5°C)

Example 2: Using a ~~manufacturer's capability curves~~Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 12**. To be consistent with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 8** and **9**, and the simplified loading curve shown in **Figure 14** (calculated using formulas from IEEE Std. C57.91).



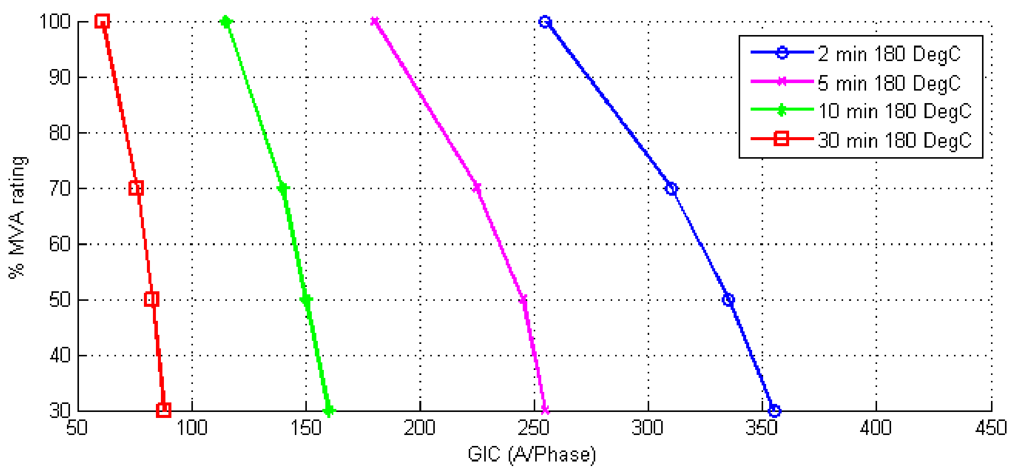
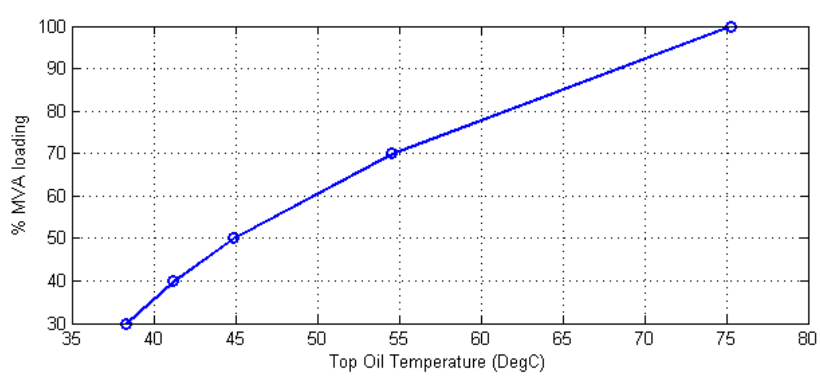


Figure 12: Capability ~~c~~Curve of a ~~transformer based~~Transformer Based on the ~~thermal response shown~~Thermal Response Shown in Figures 8 and 9.



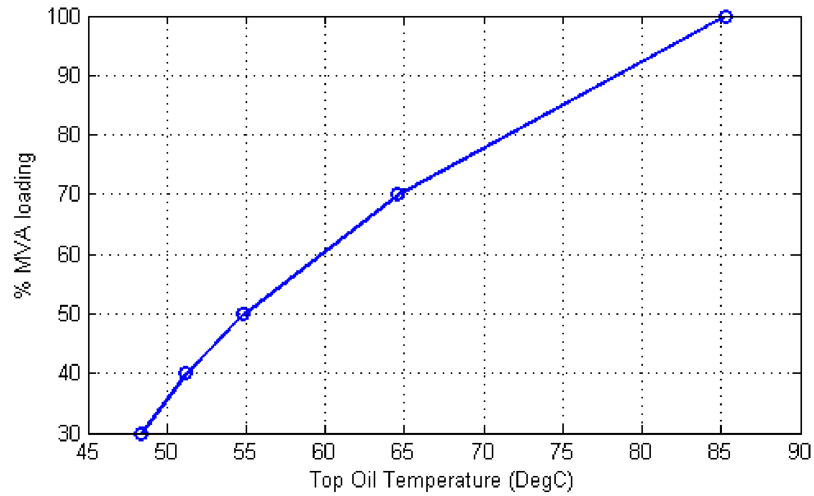


Figure 13: Simplified ~~loading curve assuming 30~~Loading Curve Assuming 40°C ~~ambient temperature~~Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve then the transformer is within its capability.

To use these curves it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 14** shows a close-up of the GIC near its highest peak superimposed to a ~~160 A/~~255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 12**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180~~3~~ A/phase at 100% loading has been superimposed on **Figure 15**. It should be noted that a ~~160~~255 A/phase, 2 minute pulse is equivalent to a ~~103A~~180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

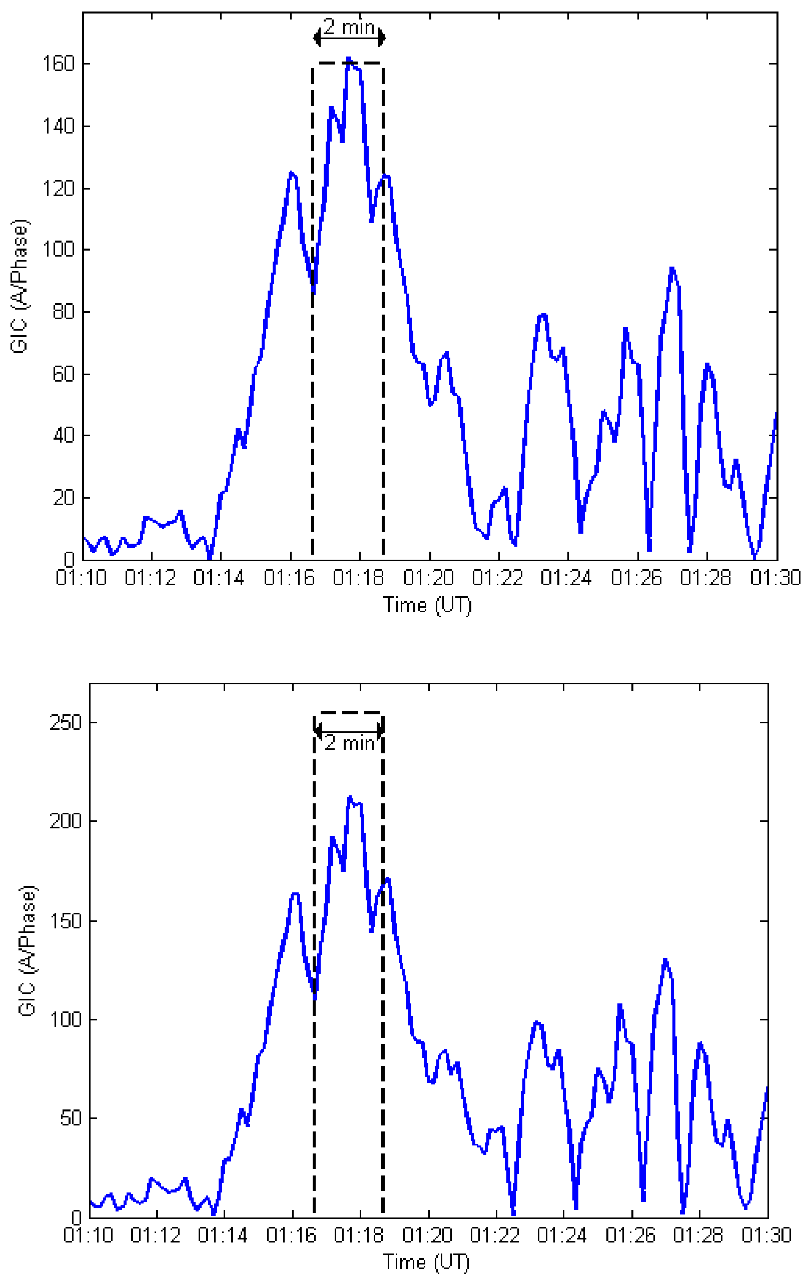
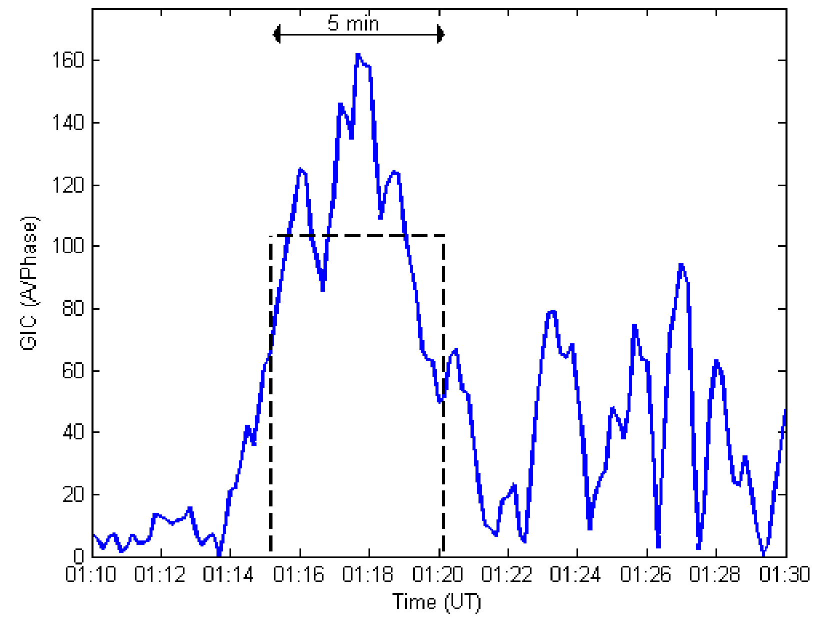


Figure 14: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load



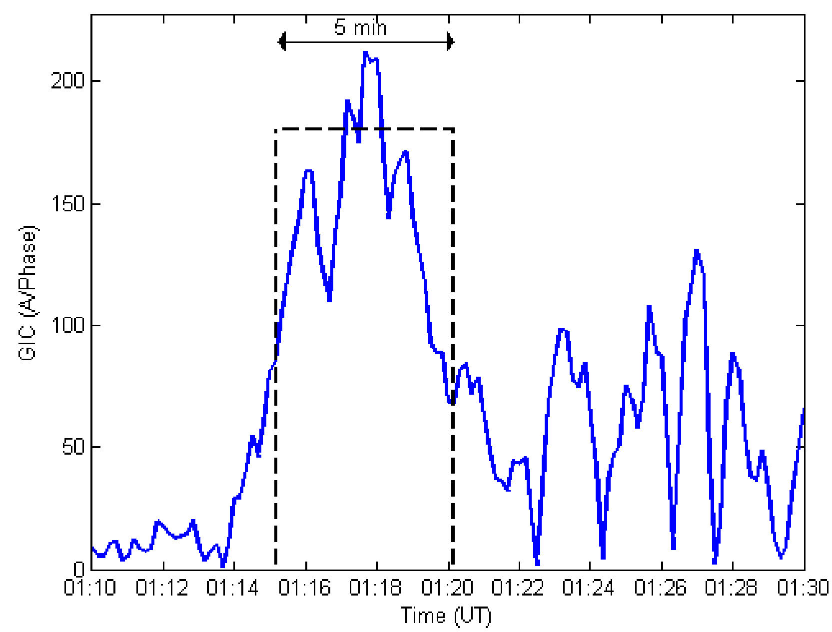
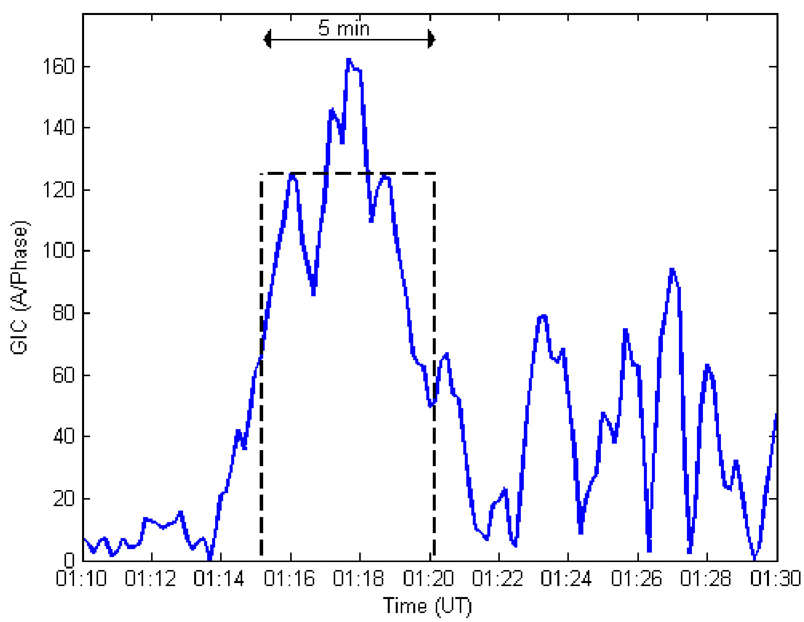


Figure 15: Close-up of GIC(t) and a ~~5 minute~~Five Minute 180 A/phase GIC ~~p~~Pulse at ~~full load~~Full Load

When using a capability curve it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), allowances have to be made in terms of prior hot spot heating. From these considerations it is ~~apparent that~~unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 12** would have amplitudes of ~~186~~310 and ~~1~~225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 16**. In this case, ~~it~~judgment is ~~not easy~~also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above or clearly below the GIC thresholds for a given pulse duration.



If a conservative threshold of 160°C were to be used to take into account the age and condition of the transformer, then a new set of capability curves would be required.

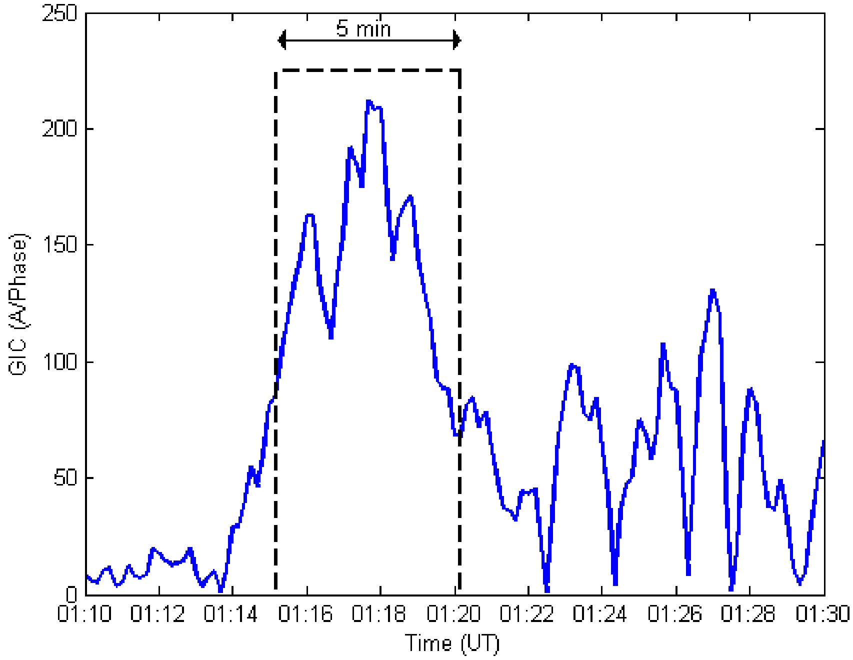


Figure 16: Close-up of GIC(t) and a 5 ~~minute~~Minute 225 A/phase GIC ~~pulse assuming 70% load~~Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 15 Amperes per phase is a conservative screening criterion. A list of reference materials is included herein.

Justification

Heating of the winding and other structural parts can occur in power transformers during a GMD event. These thermal impacts are dependent on the thermal time constants of the transformer. The following analysis of tested transformers [*See* References 1-4] assumes a long-duration 15 Amperes per phase neutral current in the transformer, which is a conservative assumption.

From IEEE Std. C57.91 2001 [5], the suggested long-time emergency loading metallic hot spot temperature is 160°C as shown in **Table 1**. The top oil temperature limit for the same operating conditions is 110 (ambient + full load). This suggests that a 50°C temperature increase for three hours for metallic part hot spot heating is a conservative and safe incremental temperature. The highest incremental asymptotic hot spot temperatures measured in [1-4] are shown in Figures 1 to 4.

TABLE 1:Excerpt from Maximum Temperature Limits Suggested in IEEE C57-91 2001

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

Figure 1 corresponds to the thermal asymptotic response of the tie plate of a 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [1]. The asymptotic behavior for GIC values above 5 Amperes per phase has been linearly extrapolated. Although such extrapolation is probably very conservative for GIC values above 40 Amperes per phase it is consistent with the thermal behavior of metallic hot spots demonstrated in other measurements (e.g., [2], [3]). The incremental asymptotic temperature for 15 Amperes per phase is 46.8 °C.

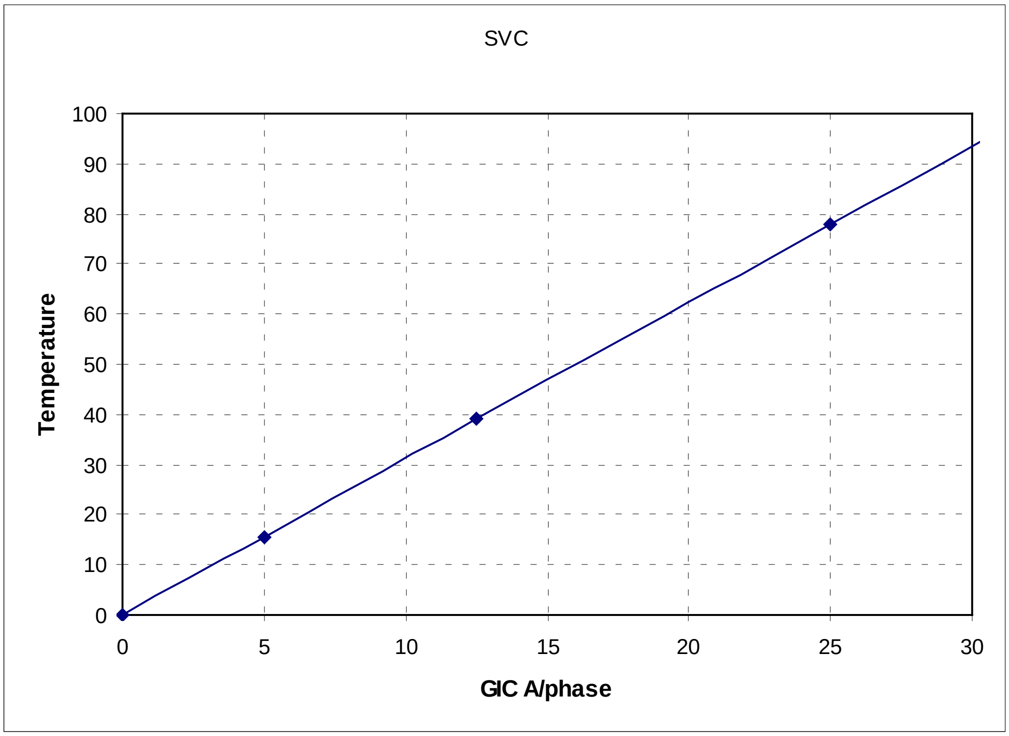


Figure 1: Asymptotic thermal response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer.

Figure 2 corresponds to the thermal asymptotic response of tie plate of a 735 kV 370 MVA single-phase core-type autotransformer [2]. The asymptotic response depicted in **Figure 2** is a combination of measurements and calculated values. In this case, 12.5 Amperes per phase caused an increase of 36 °C while 25 Amperes per phase caused an increase of 89 °C. Interpolation between these two points gives an increase of 47 °C at 15 Amperes per phase. The highest current injected into this transformer is reported as 75 Amperes per phase for 1 hour. The transformer was energized from the 735 kV terminals and weak-source uncertainties normally seen in factory floor tests [4] would have been low in these tests.

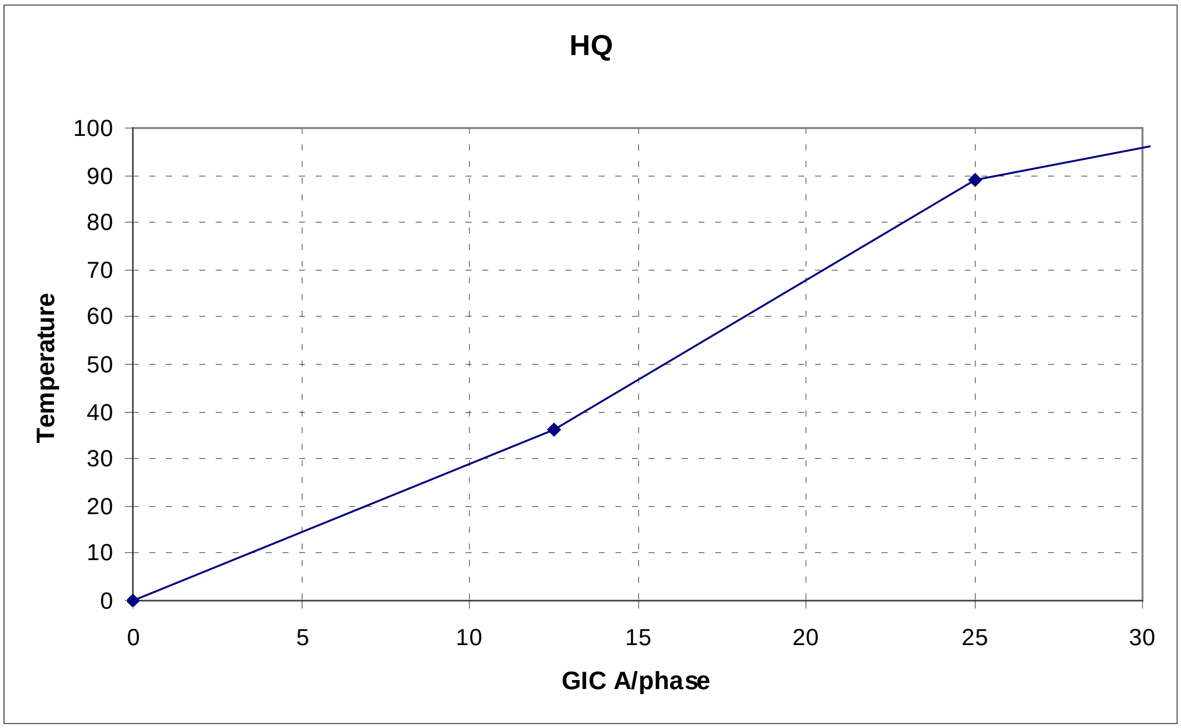


Figure 2: Asymptotic thermal response of the tie plate of a 735 kV 370 MVA single-phase core-type autotransformer.

Figure 3 corresponds to the thermal asymptotic response of the top and bottom clamps of a 400 kV 400 MVA five-leg core-type fully-wound transformer [3]. Hot spot temperature of 34 °C for 15 Amperes per phase occurred at the Flitch plate. Highest current injected into this transformer is reported as 66.67 Amperes per phase for approximately 10 minutes. The transformer was energized from the 400 kV terminals and weak-source uncertainties would have been low.

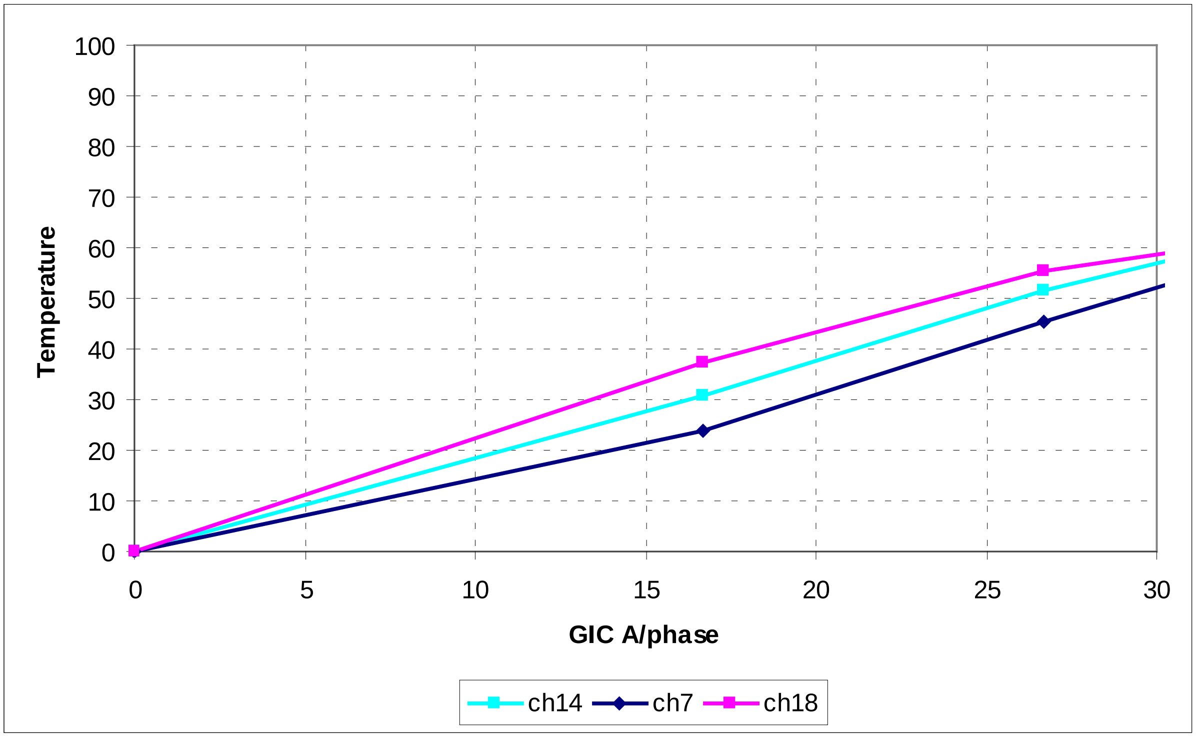


Figure 3: Asymptotic thermal responses of the bottom and top yoke clamps (ch14 and ch7), and Flitch plate (ch18) of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

Figure 4 shows tests carried out in a factory floor of a fully instrumented 400 kV 400 MVA single-phase core-type autotransformer. Tie-plate hot spot temperature of 46 °C for 15 Amperes per phase was measured. The weak ac supply is an issue in these tests and the actual asymptotic response for lower values of GIC above 10 A/phase is probably higher than measured. However at these relatively low GIC values, saturation of structural parts is not a dominant issue.

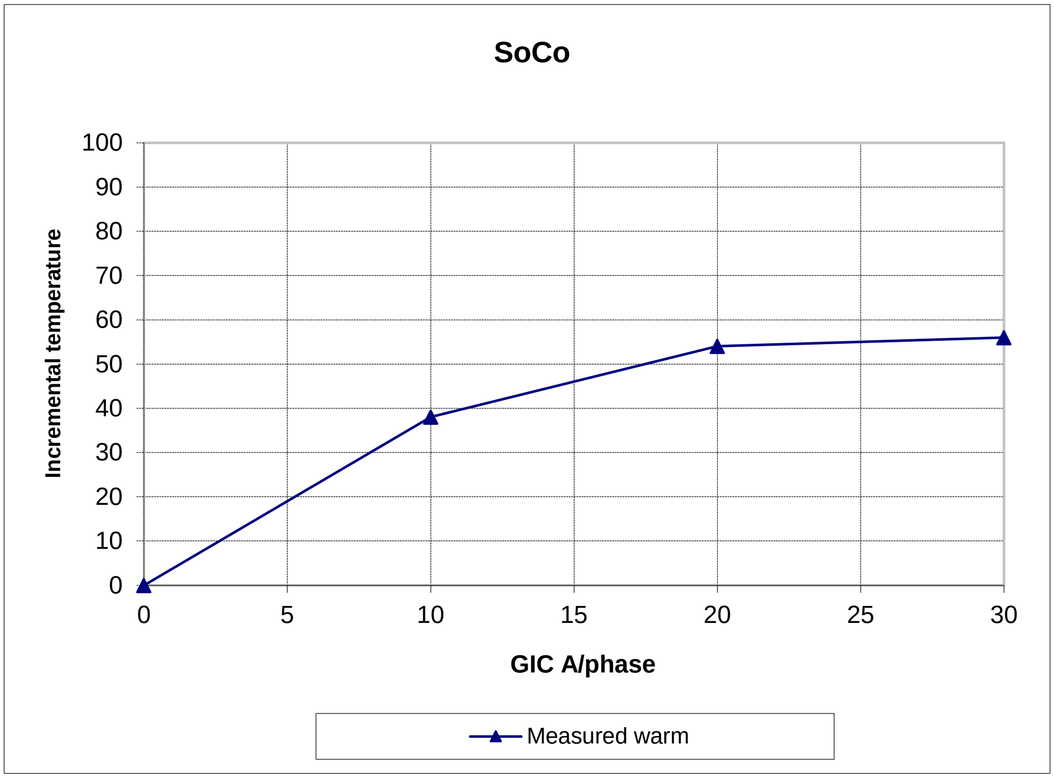


Figure 4: Asymptotic thermal responses of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

In all of the test results presented, an effective GIC value of 15 Amperes per phase resulted in a temperature increase of less than 50°C. These results strongly support use of 15 Amperes per phase as a conservative criterion for determining which applicable transformers require assessment using more detailed methods like those described in the Transformer Thermal Impact Assessment white paper [6]. Furthermore there is significant margin in the assumption of an injected dc current of 15 Amperes per phase for three hours (as opposed to GIC time series information). This conservative approach provides ample margin to account for any uncertainty resulting from the limited number of tested transformers.

References

[1] Marti, L., Rezaei-Zare, A., Narang, A. , "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery, ,* vol.28, no.1, pp.320-327, Jan. 2013

[2] Picher, R.; Bolduc, L.; Pham, V.Q., "Study of the Acceptable DC Current Limit in Core-Form Power Transformer," *Power Engineering Review, IEEE* , vol.17, no.1, pp.50,51, January 1997

[3] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[4] NERC GMD TF Presentation, Atlanta, Nov. 2013 http://www.nerc.com/comm/pc/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMDTF%20Transformer%20Session.pdf?Mobile=1&Source=%2Fcomm%2Fpc%2F_layouts%2Fmobile%2Fdispform.aspx%3FList%3Da84e3238-8456-4456-9ca7-fe46bebd7392%26View%3De8c6afc7-3ec9-4e4c-89d7-ef43bd2911d9%26ID%3D39%26CurrentPage%3D1

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[6] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Project 2013-03 (GMD Mitigation)

TPL-007-1 Common Questions and Responses
June 12, 2014

Provided below is information regarding: (i) general questions about the proposed standard and the NERC standard development process; (ii) the benchmark GMD event; (iii) the technical details of the standard requirements, including models, studies, assessments and analysis; and (iv) the applicability of the proposed standard.

This document is based on the currently posted draft of the proposed standard and is subject to change.

General

These are general questions about the standard and the NERC standard development process.

When TPL-007-1 is approved, will EOP-010-1 be retired?

No, EOP-010-1 and TPL-007-1 complement one another and together fulfill the Commission's directives in Order No. 779. EOP-010-1 – Geomagnetic Disturbance Operations provides a reliability benefit by requiring all Reliability Coordinators and applicable Transmission Operators to have Operating Plans, Processes, or Procedures to mitigate the effects of geomagnetic disturbance (GMD) events. TPL-007-1 applies to Planning Coordinators, Transmission Planners, and some transformer owners and establishes requirements for Transmission system planned performance during GMD events. If mitigation plans are required to meet performance requirements, they may include operational measures that become part of an entity's GMD Operating Plans, Processes, or Procedures.

How soon will utilities be required to implement the requirements in TPL-007-1?

The proposed implementation plan for TPL-007-1 is phased over a four-year period. In general, the following effective dates beginning the first calendar quarter after regulatory approval are proposed:

- 60 days: Planning Coordinator determines responsibilities for GMD Vulnerability Assessments in its planning area (Requirement R1)
- 14 months: Develop System models (Requirement R2)
- 18 months: Planning entities calculate geomagnetically-induced current (GIC) flows and provide to applicable Transmission Owners and Generator Owners (Requirement R5)
- 36 months: Owners complete transformer thermal impact assessments (Requirement R6)
- 48 months: GMD Vulnerability Assessments and Corrective Action Plans (Requirements R3, R4, and R7)

What periodicity is required for GMD Vulnerability Assessments? Is it related to the solar cycle?

In the proposed standard, GMD Vulnerability Assessments must be conducted once every 60 months. The periodicity is not tied to the 11-year sunspot solar cycle because the solar cycle is an indicator of the frequency of solar storms but not necessarily of their intensity.

Organization of TPL-007-1

Commenters suggested reorganizing the requirements to better reflect the order of required studies and analysis in the GMD assessment process. The SDT has made changes in the revised standard.

How has the drafting team taken into account potential costs associated with the reliability standard?

The proposed standard addresses the directives for a stage 2 GMD standard in FERC Order No. 779. In the order, FERC stated their expectation that "NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards (P.28)"

NERC Reliability Standards are technology-neutral and focus on the reliability objectives to be accomplished rather than the specific activities to be performed. The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations.

Benchmark GMD Event

Questions about the benchmark, application, and models.

Previous analysis of IMAGE magnetometer data by Antti Pulkkinen and others indicated that a 1-in-100 year storm could be expected to produce geoelectric fields of 20 V/km at the reference location. What is the justification for using a peak geoelectric field value of 8 V/km for the benchmark GMD event?

The same data set used to arrive at 20 V/km was used in the analysis presented in the white paper. The difference is that instead of characterizing an event by the magnitude of the peak in any single geomagnetic observatory, this analysis examines averaged geoelectric field values which occur simultaneously over a large geographic area. In other words, the prior research examined recorded peaks which include localized intensifications which are not suitable for evaluating wide area GMD impacts that could lead to uncontrolled cascading blackouts. The 1-in-100 year storm reference peak geoelectric field was 20 V/km in the 2012 GMD Report. With spatial averaging, the same data produces a conservative 1-in-100 year peak geoelectric field of 8 V/km for the reference geomagnetic latitude and earth model. This reference geoelectric field includes engineering margin above the 5.77 V/km value that is the calculated using extreme value analysis.

Did the drafting team consider the Carrington event or the 2012 coronal mass ejection (CME) as a basis for the Benchmark GMD Event? Yes, but the drafting team did not base the benchmark GMD event on these specific events. Data is not available that would allow direct determination of the geoelectric fields experienced during the Carrington event and estimates of the storm intensity vary. Furthermore, research suggests the occurrence rate for a Carrington event to be in a wide range of 1 in 70-600 years. The SDT applied extreme value analysis to the data set of spatially averaged IMAGE magnetometer observations to determine that a peak geoelectric field of 5.8 V/km at the reference location is a conservative estimate based on the available data. A conservative margin was added to be consistent with the visual extrapolation of the statistical data to arrive at 8 V/km. This frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is common as the storm return period for determining wind and ice loading of transmission infrastructure.

A powerful but non-Earth directed CME in 2012 was measured by space-based instruments and has been suggested by some space weather researchers as a criterion for GMD analysis of the power system. However, because the event did not impact the Earth, research models had to be utilized to assess what could have happened if the event hit the Earth's space environment. Due to the complex nature of the space weather phenomena and fairly immature state of space science models, such model-based assessments contain inherent uncertainties that are not well known or understood at present time. Consequently, the drafting team did not base the benchmark GMD event on this CME event.

An earth model for southern and central Florida is not available through the U.S. Geological Survey website. What model or scaling factor for earth conductivity should be used?
TPL-007-1 and the Benchmark GMD Event Description white paper include calculated scaling factors to account for all of the earth conductivity models available on the USGS and Natural Resources Canada (NRCan) websites. These cover the majority of the North America. A planner may always use a technically-sound earth model for the planning area, even when a USGS model is available. With an earth model, the plane wave method can be used to calculate the peak geoelectric field from the reference geomagnetic time series or waveshape. This is described in the Application Guide for Computing GIC in the Bulk-Power System:
(http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf)

Additionally, Attachment 1 now states that when a ground conductivity model is not available, either from USGS or some other technically-supportable source, the planning entity should use the resistive reference ground model (Beta = 1).

Is the 10-s magnetometer data for the waveform available?
The file is posted on the GMD Task Force web page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

Models, Studies, Assessments, and Analysis

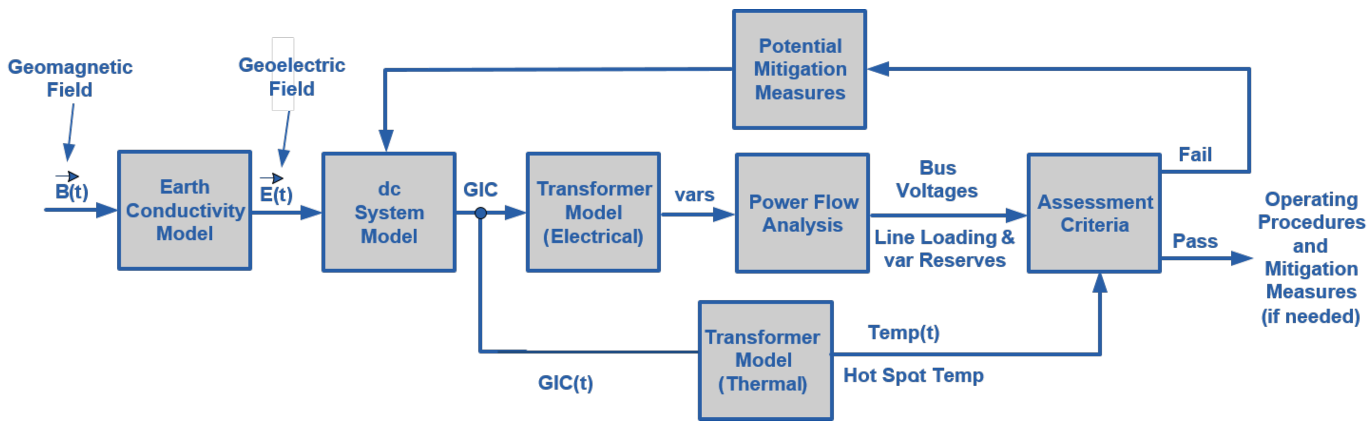
Questions about the technical details of the TPL-007-1 requirements.

What analysis is required by TPL-007-1?

In the proposed standard, planning entities must conduct power flow analysis that accounts for var absorption in power transformers as a result of GIC from the benchmark GMD event. In the System being analyzed, Reactive Power compensation devices and other Transmission Facilities should be removed if the planner determines that Protection Systems may trip the devices or Facilities due to the effects of harmonics. The planner may make this determination based on harmonics analysis or may use a screening approach that accounts for the type of the Protections System in use. The standard does not require entities to perform stability analysis.

The proposed standard also requires applicable owners to conduct a transformer thermal impact assessment. Examples of technically-justified approaches are described in the Transformer Thermal Impact Assessment white paper.

An overall diagram of the GMD Vulnerability Assessment process is provided in the diagram below:



The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

Guidance for developing the GIC System model is provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk-Power System. The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Is N-1 contingency analysis required?

The proposed standard does not require traditional contingency analysis described in TPL-001. In performing the analysis in TPL-007 Table 1 the planner removes all equipment that is deemed to be susceptible to tripping due to harmonics. This study addresses the directives in the FERC order and examines a potential effect of severe GMD events such as the tripping of SVCs in the 1989 Hydro-Quebec event that resulted in blackout.

When considering loss of Reactive Power compensation devices and other Transmission Facilities in the steady state analysis required by Table 1, is the planner expected to consider the loss individually (one-at-a-time) or simultaneously (all-at-once)?

Facilities that may be susceptible to tripping should be removed from the System being analyzed to simulate simultaneous common-mode failure, as occurred to SVCs during the 1989 Hydro Quebec event. The planner may make this determination based on a harmonics analysis or may use a screening approach that accounts for the type of Protection System in use. Conservative engineering judgment should be applied and supported in the analysis.

Do applicable entities in lower latitudes have to do the same studies as those in higher latitudes?

Yes, TPL-007 is a continent-wide standard and requires that system studies be conducted by all applicable planning entities. However, transformer thermal impact assessment is only required when the maximum effective GIC at the power transformer is 15 Amperes per phase or greater.

Where does the geomagnetically-induced current (GIC) time-series information necessary for the Transmission Owner's thermal assessment come from?

The transformer thermal impact assessment specified in TPL-007 is based on GIC time series information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC system model and must be provided to the owning entity responsible for conducting the thermal impact assessment.

The maximum effective GIC value (provided in R5 part 5.1) is used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated. The effective GIC time series, GIC(t), (provided in R5 part 5.2) is used to conduct the transformer thermal impact assessment (see white paper for details).

In addition to transformers, other elements of the Bulk-Power System may be susceptible to the effects of GIC. Does the standard address any other equipment impacts?

In the System being analyzed, Reactive Power compensation devices and other Transmission Facilities that the planner determines have Protection Systems that may trip due to the effects of harmonics should be removed. The planner may make this determination based on a harmonics analysis or may use a screening approach that accounts for the type of hardware in use by the Protection System. Guidance for making these determinations is contained in the GMD Planning Guide:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

Why are generator impacts not specifically addressed in TPL-007? 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.

How should a planning entity account for adjacent systems in the GMD Vulnerability Assessment steady state analysis?
Reactive Power losses in neighboring systems will affect the analysis of the system in the planning area. An acceptable approach for considering these losses is to model two or more key buses into the neighboring network. For systems that are considerably smaller than those adjacent to them, additional buses may need to be included in the model. This is described in the GMD Planning Guide, available here: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

How does TPL-007-1 address concerns that mitigation actions in one system may adversely affect reliability in a neighboring system? The proposed standard requires planning entities to provide their Corrective Action Plans to their Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners. An entity with reliability concerns resulting from the Corrective Action Plan is expected to resolve their concerns, which could include submitting written comments to the originator of the Corrective Action Plan. TPL-007-1 requires planning entities to respond to documented comments on their Corrective Action Plan within 90 calendar days of receipt.

Where do I get transformer thermal models? Models may be available from the manufacturer or in published technical literature. The GMD Task Force is in the process of publishing conservative default models on the basis of testing and published information. Implementation plan provides time to obtain the necessary models.

Applicability

These questions concern what entities and equipment are applicable in the proposed standard.

Are any geographic areas or regions exempt from the standard?
No geographic areas or regions are exempt from the proposed standard. TPL-007-1 is a continent-wide standard to meet the FERC directives for assessments of the potential impact of a benchmark GMD event on the Bulk-Power System equipment and Bulk-Power System as a whole (P.56-62). However, the standard does not ignore the geographic variability of GMD events. The benchmark GMD event is tailored to the specific location of the system being analyzed through scaling factors that account for geomagnetic latitude and earth conductivity models.

What functional entities are applicable to the proposed standard?
The proposed standard will establish planned performance requirements during a benchmark GMD event and is applicable to Planning Coordinators, Transmission Planners, Transmission Owners, and Generation

Owners with transformers or areas with transformers that have a high-side, wye-grounded winding connected at 200 kV or higher. The drafting team used the NERC Functional Model as a guide in determining applicability. The selected entities have functions that enable them to meet the FERC directives to evaluate the effects of GICs on Bulk-Power System transformers and other equipment (P.67), consider wide-area effects and coordinate across regions (P.67), and develop plans to address potential impacts (P. 79). Justification for the 200 kV voltage threshold may be found in the whitepaper that was developed by the drafting team for the stage 1 standard, EOP-010-1 – Geomagnetic Disturbance Operations. In requirement R1, the Planning Coordinator determines the responsibilities for planning entities in the planning area. Based on this determination, subsequent requirements for maintaining models, conducting studies and assessments, and distributing information must be completed by the appropriate responsible entity.

Are instrument transformers or station services transformers considered applicable within the TPL-007-1 standard? Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, they are not included in the applicability for this standard. These types of transformers have much higher resistances compared to power transformers and would not result in significant effect on station GIC flows.

Is the standard limited to Bulk Electric System equipment? No; the requirements in TPL-007-1 apply to any Planning Coordinator, Transmission Planner, Generator Owner, or Transmission Owner with Facilities listed in section 4.2 of the standard. Any power transformer with high side, wye-grounded winding with terminal voltage greater than 200 kV may have potential impacts that must be included in a GMD planning study.

Can the standard provide an entity applicability / screening criteria on basis of geoelectric field? No, but the SDT has developed a technically-supported screening criteria for thermal assessment on the basis of GIC.

What is the role of the Reliability Coordinator (RC) in TPL-007-1? The RC is not an applicable entity in the planning standard, but they will receive information as a result of planning studies conducted in TPL-007 in accordance with R7.

Standards Announcement Reminder

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Ballot and Non-Binding Poll Now Open through July 30, 2014

Now Available

A ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Wednesday, July 30, 2013**.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Formal Comment Period Now Open through July 30, 2014
Ballot Pools Being Formed through July 14, 2014

Now Available

A 45-day formal comment period for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern on Wednesday, July 30, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pool

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast a ballot. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project is:

Ballot: bp-2013-03_TPL-007-1_in@nerc.com
Non-Binding Poll: bp-2013-03_TPL-007-1_NB_in@nerc.com

Next Steps

A ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 21-30, 2014**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Formal Comment Period Now Open through July 30, 2014
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A 45-day formal comment period for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern on Wednesday, July 30, 2013**.

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Non-Binding Poll: bp-2013-03_TPL-007-1_NB_in@nerc.com

Next Steps

A ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 21-30, 2014**

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Monitoring

Ballot and Non-Binding Poll Results

Now Available

A ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, July 30, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results	Non-Binding Poll Results
Quorum /Approval	Quorum/Supportive Opinions
82.67% / 55.77%	82.56% / 58.65%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2013-03 GMD TPL-007-1
Ballot Period:	7/21/2014 - 7/30/2014
Ballot Type:	Initial
Total # Votes:	310
Total Ballot Pool:	375
Quorum:	82.67 % The Quorum has been reached
Weighted Segment Vote:	55.77 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	107	1	47	0.595	32	0.405	0	7	21
2 - Segment 2	8	0.6	2	0.2	4	0.4	0	0	2
3 - Segment 3	86	1	36	0.537	31	0.463	0	4	15
4 - Segment 4	24	1	12	0.75	4	0.25	0	3	5
5 - Segment 5	79	1	32	0.533	28	0.467	0	6	13
6 - Segment 6	54	1	24	0.533	21	0.467	0	3	6
7 - Segment 7	3	0.2	1	0.1	1	0.1	0	0	1
8 - Segment 8	5	0.4	1	0.1	3	0.3	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.6	4	0.4	2	0.2	0	1	0
Totals	**375**	**6.9**	**160**	**3.848**	**126**	**3.052**	**0**	**24**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Bee from Exelon)
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston		
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
				SUPPORTS THIRD PARTY COMMENTS -

1	Gainesville Regional Utilities	Richard Bachmeier	Negative	(FRCC GMD Task Force) - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force) - (FMPA)
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Ruskamp - LES)
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support NPPD comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group Comments)

1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines of PGE will file comments separately in support of this negative vote.)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Suport Comments of Public Service Enterprise Group ("PSEG"))
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz		
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	

1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley		
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg		
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Regional

				Entity Committee and Compliance Forum)
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall, Colorado Springs Utilities)
3	ComEd	John Bee	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georga transmission)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force) - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aeci)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines)
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
				SUPPORTS THIRD PARTY

3	Tampa Electric Co.	Ronald L. Donahey	Negative	COMMENTS - (FRCC RECCF group comments)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC Comments)
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF))
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kederowski of We Energies)
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Coments previously submitted by AZPS)

5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Regional Entity Committee and Compliance Forum (RECCF))
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Bee from Exelon)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force) - (Florida Municipal

				Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	Nevada Power Co.	Richard Salgo	Negative	SUPPORTS THIRD PARTY COMMENTS - (PacifiCorp)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines PGE)
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG comments submitted by John Seelke)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments filed by FRCC RECCF)

5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Southern Indiana Gas and Electric Co.	Rob Collins	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - American Electric Power)
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI comment)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Bee from Exelon)
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
6	Florida Municipal Power Pool	Thomas Reedy	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force) - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	

6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Negative	COMMENT RECEIVED
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Abstain	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments filed by FRCC RECCF)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See the FRCC RECCF group comments)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel		
				COMMENT

8	Foundation for Resilient Societies	William R Harris	Negative	RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Negative	COMMENT RECEIVED
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Non-Binding Poll Results

Project 2013-03 Geomagnetic Disturbance Mitigation

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-03 GMD TPL-007-1
Poll Period:	7/21/2014 - 7/30/2014
Total # Opinions:	284
Total Ballot Pool:	344
Summary Results:	82.56% of those who registered to participate provided an opinion or an abstention; 58.65% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	City of Tallahassee	Daniel S Langston		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilties)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines of PGE will submit comments separately in support of this negative vote.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL

				NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO

				Council Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley		
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg		
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Regional Entity Committee and Compliance Forum)
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Kaleb Brimhall, Colorado Springs Utilities)
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia transmission)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aeci)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines)

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC RECCF group comments)
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC Comments)
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF))
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kederowski of We Energies)
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments previously submiteed by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Regional Entity Committee and Compliance

				Forum (RECCF))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	

5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines)
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments

				filed by FRCC RECCF)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI comment)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
6	Florida Municipal Power Pool	Thomas Reedy	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Abstain	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Abstain	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments filed by FRCC RECCF)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	

6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See the FRCC RECCF group comments)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
7	Luminant Mining Company LLC	Stewart Rake	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel		
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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 ɑ 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.

Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard

A White Paper by:

John G. Kappenman, Storm Analysis Consultants

and

Dr. Willam A. Radasky, Metatech Corporation

July 30, 2014

Executive Summary

The analysis of the US electric power grid vulnerability to geomagnetic storms was originally conducted as part of the work performed by Metatech Corporation for the Congressional Appointed US EMP Commission, which started their investigations in late 2001. In subsequent work performed for the US Federal Energy Regulatory Commission, a detailed report was released in 2010 of the findings[11]. In October 2012, the FERC ordered the US electric power industry via their standards development organization NERC to develop new standards addressing the impacts of a geomagnetic disturbance to the electric power grid. NERC has now developed a draft standard and has provided limited details on the technical justifications for these standards in a recent NERC White Paper[22].

The most important purpose of design standards is to protect society from the consequences of impacts to vulnerable and critical systems important to society. To perform this function the standards must accurately describe the environment. Such environment design standards are used in all aspects of society to protect against severe excursions of nature that could impact vulnerable systems: floods, hurricanes, fire codes, etc., are relevant examples. In this case, an accurate characterization of the extremes of the geomagnetic storm environment needs to be provided so that power system vulnerabilities against these environments can be accurately assessed. A level that is arbitrarily too low would not allow proper assessment of vulnerability and ultimately would lead to inadequate safeguards that could pose broad consequences to society.

However from our initial reviews of the NERC Draft Standard, the concern was that the levels suggested by NERC were unusually low compared to both recorded disturbances as well as from prior studies. Therefore this white paper will provide a more rigorous review of the NERC benchmark levels. NERC had noted that model validations were not undertaken because direct measurements of geo-electric fields had not been routinely performed anyway in the US. In contrast, Metatech had performed extensive geo-electric field measurement campaigns over decades for storms in Northern Minnesota and had developed validated models for many locations across the US in the course of prior investigations of US power grid vulnerability[3]. Further, various independent observers to the NERC GMD tasks force meetings had urged NERC to collect decades of GIC observations performed by EPRI and independently by power companies as these data could be readily converted to geo-electric fields via simple techniques to provide the basis for validation studies across the US. None of these actions were taken by the NERC GMD Task Force.

It needs to be pointed out that GIC measurements are important witnesses and their evidence is not being considered by the NERC GMD Task Force in the development of these standards. GIC observations provide direct evidence of all of the uncertain and variable parameters including the deep Earth ground response to the driving geomagnetic disturbance environment. Because the GIC measurement is also obtained from the power grid itself, it incorporates all of the meso-scale coupling of the disturbance environments to the assets themselves and the overlying circuit topology that needs

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[1] *Geomagnetic Storms and Their Impacts on the U.S. Power Grid* (**Meta-R-319**), John Kappenman, Metatech Corporation, January 2010. Via weblink from Oak Ridge National Lab, *wttp://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml*

[2] NERC Benchmark Geomagnetic Disturbance Event Description, *http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Benchmark_GMD_Event_April21_2.pdf*

[3] Radasky, W. A., M. A. Messier, J. G. Kappenman, S. Norr and R. Parenteau, "Presentation and Analysis of Geomagnetic Storm Signals at High Data Rates", IEEE International Symposium on EMC, August 1993, pp. 156-157.

to be assessed. Separate discreet measurements of geo-electric fields are usually done over short baseline asset arrays which may not accurately characterize the real meso-scale interdependencies that need to be understood. The only challenge is to interpret what the GIC measurement is attempting to tell us, and fortunately this can be readily revealed with only a rudimentary understanding of Ohm's Law, geometry and circuit analysis methods, a tool set that are common electrical engineering techniques. Essentially the problem reduces to: *"if we know the I (or GIC) and we know the R and topology of the circuit, then Ohm's law tells us what the V or geo-electric field was that created that GIC"*. Further since we know the resistance and locations of power system assets with high accuracy, we can also derive the geo-electric field with equally high certainty. These techniques allow superior characterization of deep Earth ground response and can be done immediately across much of the US if GIC measurements were made available. Further these deep Earth ground responses are based upon geological processes and do not change rapidly over time. Therefore even measurements from one storm event can characterize a region. Hence this is a powerful tool for improving the accuracy of models and allows for the development of accurate forward looking standards that are needed to evaluate to high storm intensity levels that have not been measured or yet experienced on present day power grids. Unfortunately this tool has not been utilized by any of the participants in the NERC Standard development process.

It has been noted that the NERC GMD Task Force has adopted geo-electric field modelling techniques that have been previously developed at FMI and are now utilized at NRCan. The same FMI techniques were also integrated into the NASA-CCMC modeling environments and that as development and testing of US physiographic regional ground models were developed, efforts were also undertaken by the USGS and the NOAA SWPC to make sure their geo-electric field models were fully harmonized and able to produce uniform results. However, it appears that none of these organizations really did any analysis to determine if the results being produced were at all accurate in the first place. For example when recently inquired, NRCan indicated they will perhaps begin capturing geo-electric field measurements later this year to validate the base NERC Shield region ground model, a model which provides a conversion for all other ground models. In looking at prior publications of the geo-electric field model carried out in other world locations, it was apparent that the model was greatly and uniformly under-predicting for intense portions of the storms, which are the most important parameters that need to be accurately understood.

In order to examine this more fully, this white paper will provide the results of our recent independent assessment of the NERC geo-electric field and ground models and the draft standard that flows from this foundation. Our findings can be concisely summarized as follows:

- Using the very limited but publicly available GIC measurements, it can be shown how important geo-electric fields over meso-scale regions can be characterized and that these measurements can be accurately assessed using the certainty of Ohm's Law. This provides a very strict constraint on what the minimum geo-electric field levels are during a storm event.

- When comparing these actual geo-electric fields with NERC model derived geo-electric fields, the comparisons show a systematic under-prediction in all cases of the geo-electric field by the NERC model. In the cases examined, the under prediction is particularly a problem for the rapid rates of change of the geomagnetic field (the most important portions of the storm events) and produce errors that range from factor of ~2 to over factor of ~5 understatement of intensity by the NERC models compared to actual geo-electric field measurements. These are enormous errors and are not at all suitable to attempt to embed into Federally-approved design standards.

- These enormous model errors also call into question many of the foundation findings of the NERC GMD draft standard. The flawed geo-electric field model was used to develop the peak geo-electric field levels of the Benchmark model proposed in the standard. Since this model understates the actual geo-electric field intensity for small storms by a factor of 2 to 5, it would also understate the maximum geo-electric field by similar or perhaps even larger levels. Therefore this flaw is entirely integrated into the NERC Draft Standard and its resulting directives are not valid and need to be corrected.

The findings here are also not simply a matter of whether the NERC model agrees with the results of the Metatech model. Rather the important issue is the degree that the NERC model disagrees with actual geo-electric field measurements from actual storm events. These actual measurements are also confirmed within very strict tolerances via Ohm's Law, a fundamental law of nature. The results that the NERC model has provided are not reliable, and efforts by NERC to convince otherwise and that utilization of GIC data cannot be done are simply misplaced. Actual data provides an ultimate check on unverified models and can be more effectively utilized to guide standard development than models because as Richard Feynman once noted; "Nature cannot be fooled"!

Introduction to NERC Model Evaluation and Validation Overview

A series of case study examples will be provided in this White Paper to illustrate the evaluation of geo-electric fields derived from GIC measurements across the US electric power grid. These derived geo-electric field results will then be compared to the NERC estimated geo-electric fields for the same storm events and scenarios. There are an important number of underlying principles to this analysis that can be summarized as follows:

- Using past storms and by modeling detailed power networks and comparing to GIC measurements at particular locations is the best way to validate overall storm-phenomena/power grid models. It accounts for the "interpolation" of the incident measured B-fields (including the angular rotation of the fields with time), the accuracy of the ground model used, the coupling to the power network, and the computation of the current flow at the measurement point.

- Experience has shown that over times of minutes, the geomagnetic field will rotate its direction and therefore every transformer in a network will have a sensitivity to particular vector orientations of the field, and the maximum current measured at a given transformer location will be a function of the rate of change intensity of the geomagnetic field, the resulting geo-electric field this causes and the angle of the field as it changes over the storm event. This is why the rate of change (dB/dt) and GIC at a single transformer will not scale perfectly with the maximum value of dB/dt, but taking into consideration all of these topology and orientation factors, a highly accurate forensic analysis can be performed.

- Geomagnetic storms are not steady state events, rather they are events with aperiodic extreme impulsive disturbances that can occur over many hours or days duration. Modeling these events to derive a geo-electric field is challenging but readily achievable. Since these events are time domain problems, modeling solutions using time-domain methods are recommended. The NERC modeling methods that will be evaluated here have generally been developed using Fourier transform frequency domain methods. In these implementations of Fourier methods, the primary question is the accuracy in dealing with the phase of the Fourier transforms.

- When referring to impulsive geomagnetic field disturbance events, these are typically multiple discrete events with times of several minutes. Note that the collapse of the Quebec power network in March 1989 occurred in 93 seconds. Clearly times of only a few minutes are important and it is vital that the geo-electric field intensity of these transients be accurately portrayed and not understated in a Design Standard type document. For example, a 10 meter dyke defined by the standard does no good, if the actual Tsunami height is 15 meters. Any efforts to claim that models that depict some satisfactory averaging over extended time periods as being sufficient must be vigorously refuted, as these peak inflection points are the most vital aspects of the storm environments that must be accurately determined.

Simulation Model Validation – Maine Grid Examples

In the analysis carried out for the FERC Meta-R-319 report, extensive efforts were undertaken to verify that the simulation models for the US power grid were providing sufficiently accurate results. One of the primary approaches that were utilized to test these models were to perform simulations for forensic analysis purposes and to compare the results with discrete measurements that were available.

One of the forensic simulations was conducted on the Maine grid and provided important verification of the ability of the model in that portion of the US grid to produce accurate estimates. Figure 1 provides a plot of the results of this simulation showing the “Calculated” versus “Measured” GIC (geomagnetically induced current) at the Chester Maine 345kV transformer. This was for a storm which occurred on May 4, 1998 and was driven by the large scale storm conditions as shown in Figure 2.

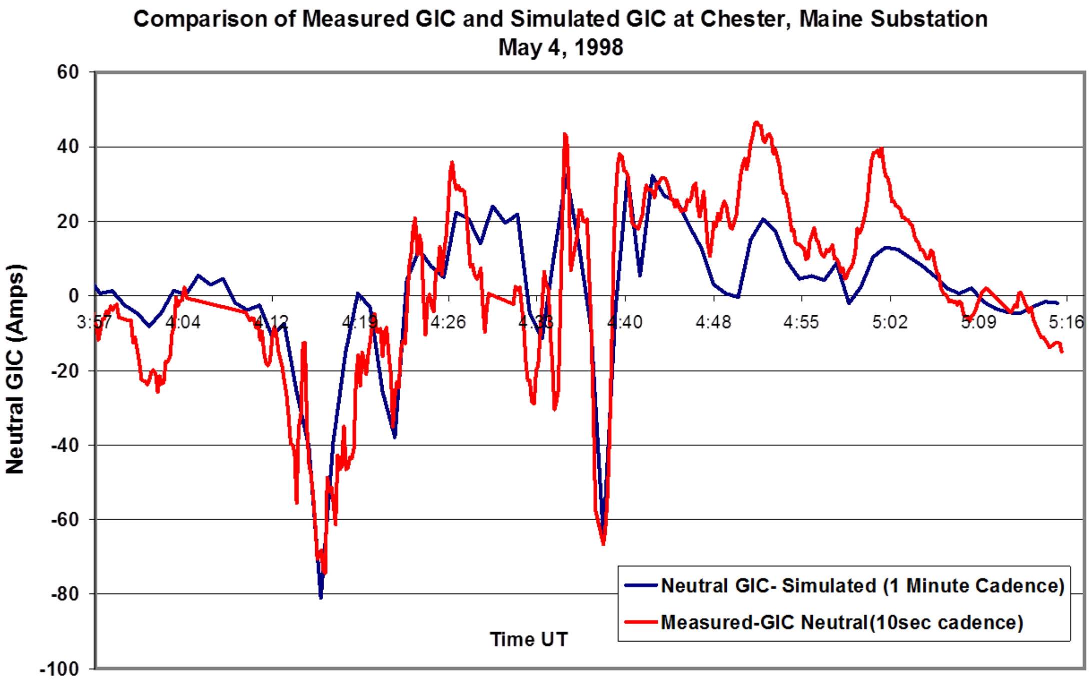

Figure 1 – Plot showing comparison of Simulated versus Measured GIC at Chester Maine 345kV transformer for May 4, 1998 geomagnetic storm. (Source – Meta-R-319)

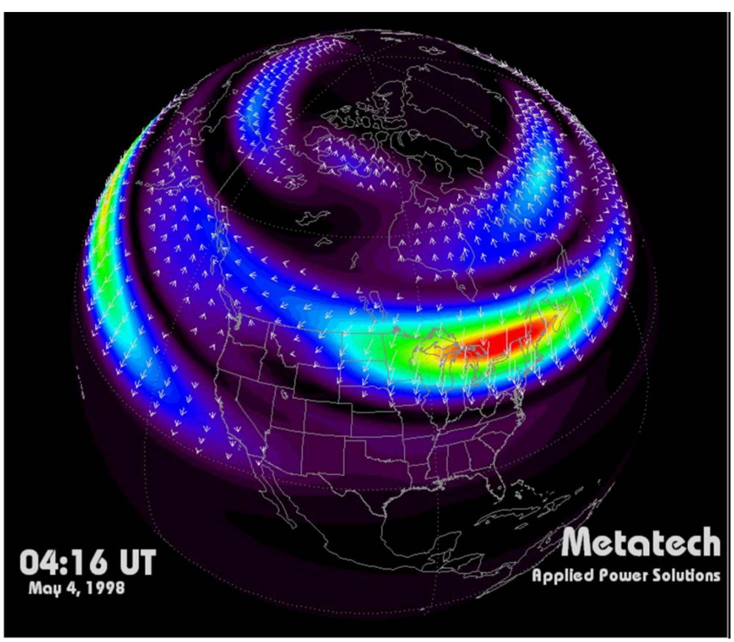

Figure 2 – Map of Geomagnetic Disturbance conditions at 4:16UT during May 4, 1998 storm. (Source – Meta-R-319)

The results in Figure 1 provide a comparison between high sample rate measured GIC (~10 second cadence) versus storm simulations that were limited to 1 minute cadence geomagnetic observatory data inputs (B-fields). Due to this limitation of inputs to the model, the model would not be able to reproduce all of the small scale high frequency variations shown in the measured data. However, the simulation does provide very good accuracy and agreement on major spikes in GIC observed, the most important portion of the simulation results that need to be validated. Figure 3 provides a wider view of the impact of the storm in terms of other GIC flow conditions in the Maine and New England region electric power grid, this is provided at time 4:16UT.

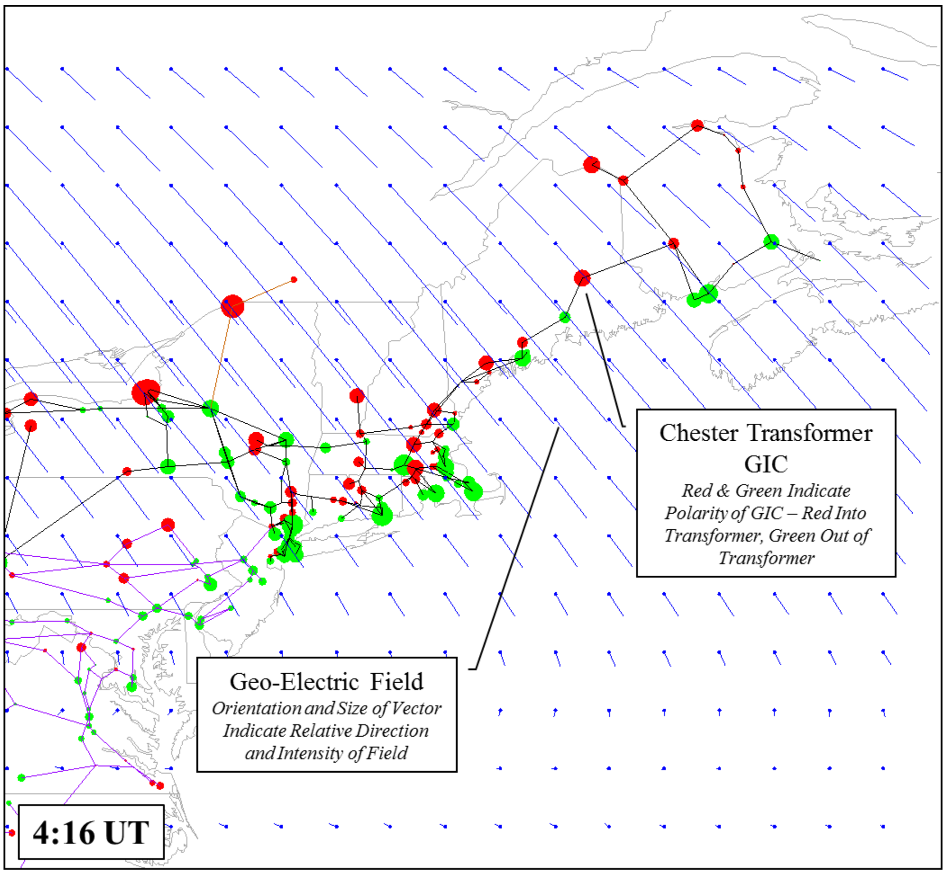

Figure 3 – GIC flows and disturbance conditions in Maine/New England grid at 4:16UT, May 4, 1998. (Source – Meta-R-319)

As this illustration shows, the Chester GIC flow is shown along with comparable GIC flows in a number of other locations in the regional power grid at one minute in time. In addition to impacts to the New England grid, extensive power system impacts were also observed to voltage regulation in upstate New York region due to storm. In this map, the intensity and polarity of GIC flows are depicted by red or green balls and their size, the larger the ball the larger the GIC flow and the danger it presents to the transformer and grid. Also shown are the blue vector arrows which are the orientation and intensity of the geo-electric field which couples to the topology of the electric grid and produces the GIC flow patterns that develop in the grid. It is noted that during the period of this storm, the electric fields rotated and all transformers in the grid would experience a variation in the pattern of GIC flows.

Considerable scientific and engineering examination has been performed since the release of the Meta-R-319 report; the report and other subsequent examinations are in close agreement on a number of important parameters of future severe geomagnetic storm threat conditions. For example, it is now well-accepted that severe storm intensity disturbance intensity can reach level of 5000 nT/min at the latitudes of the Maine power grid. NRCan now provides estimates of geo-electric fields for the nearby Ottawa observatory for storms including the May 4, 1998 storm. The ability therefore exists to do cross-validations with this and other proposed NERC ground models and geo-electric field calculation methods.

Observations of GIC at the Chester Maine substation also provide important observational confirmations that allow empirical projection of GIC levels that are plausible at more severe storm intensities. Earlier this year, the Maine electric utilities provided a limited summary of peak GIC observations from their Chester transformer and storm dates to the Maine Legislature. Figure 4 provides a graphical summary that was derived of the peak GIC and peak disturbance intensities (in nT/min) observed at the Ottawa Canada geomagnetic observatory for a number of reported events. The Maine utilities did not provide accurate time stamps (just date only), so that limits some of the ability to accurately correlate disturbance intensity to GIC peaks as the knowledge of timing is extremely coarse. Also since the Ottawa observatory is approximately 550km west of Chester, there is some uncertainty to local storm intensity specifics near Chester. However as shown, there are clear trend lines and uncertainty bounding of the level of GIC and how the GIC increases for increasing storm intensity. This trend line is quite revealing even with all of the previously mentioned uncertainties on the spatial and temporal aspects of the threat environments.

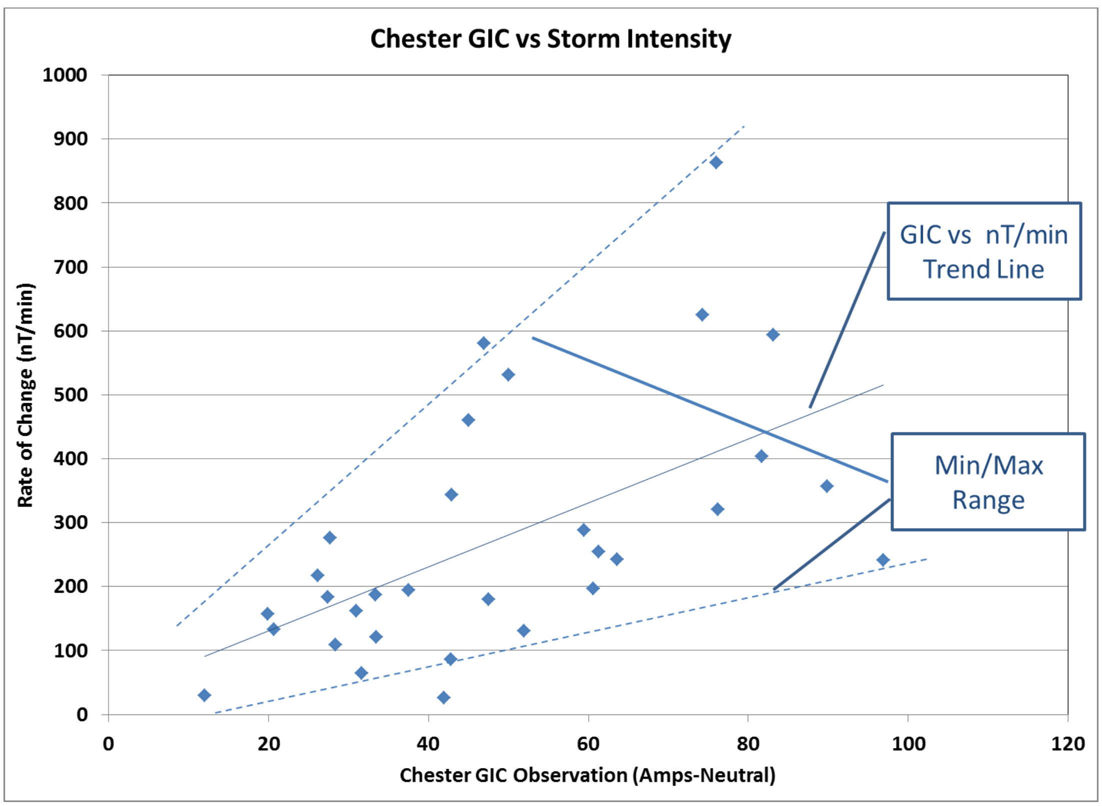

Figure 4 – GIC versus Storm Intensity (nT/min) from multiple observed GIC storm events at Chester Transformer, in this case the GIC timing is extremely coarse.

At higher storm intensities, the geo-electric field increases and if only intensity changes (as opposed to spectral content), then the increase in geo-electric field and resulting GIC will be linear. Because storm intensity for very severe storms can reach ~5000 nT/min, this graph can be linearly extended to project the range of GIC flows in the Chester transformer for these more extreme threat conditions. Figure 5 provides a plot similar to that in Figure 4, only with linear extensions of the GIC flow that this observational data estimates.

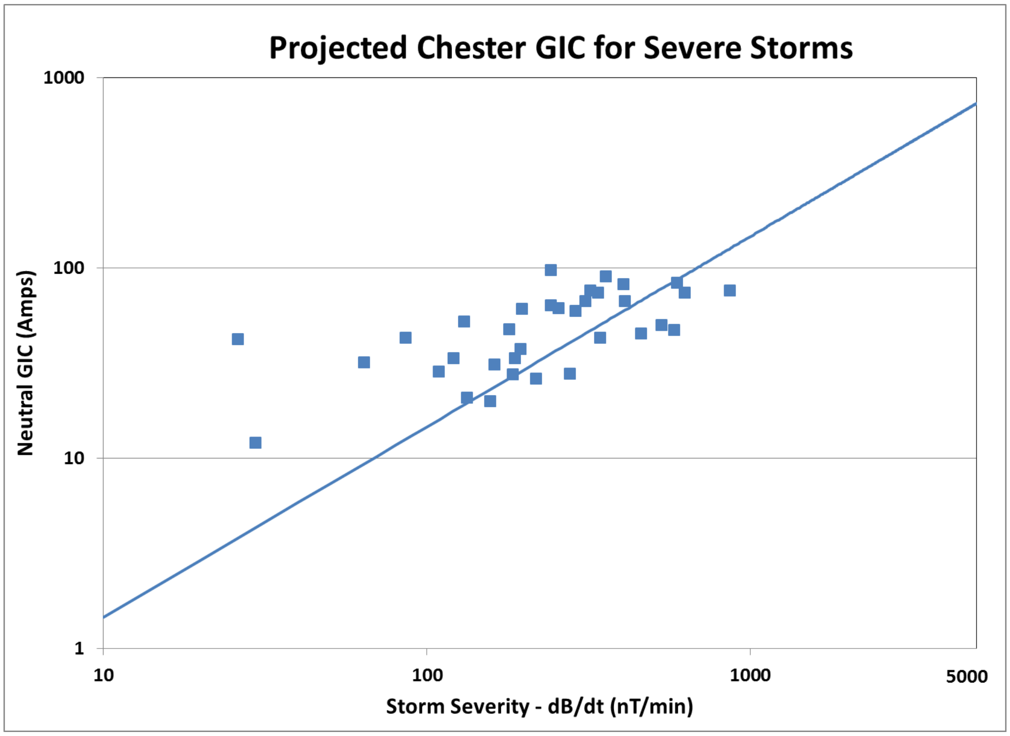

Figure 5 – Projected Chester GIC flow for storm intensity increasing to ~5000 nT/min.

Using these data plotting techniques with the previously noted uncertainties, a more detailed examination can be performed for one of the specific storm events which occurred on May 4, 1998. Figure 6 provides again the earlier described GIC plots from Figure 1. Two particularly important peak times are also highlighted on this plot at 4:16UT and 4:39UT where the recorded GIC reaches peaks respectively of -74.3 Amps and -66.6 Amps. These comparisons also show very close agreement with the simulation model results as well. Therefore the peak data points can be more explicitly examined in detail, as a comparison to how GIC vs dB/dt was plotted in Figure 4. In addition to this GIC observation data, there was also dB/dt data observed from a local magnetometer for this storm, which also greatly reduces the uncertainty of the threat environment.

Having all of this data available will aid in utilizing the power system itself as an antenna that can help resolve the geo-electric field intensity that the complex composition of ground strata generates during this storm event. Further once this response is empirically established, this same ground response can be reliably utilized to project to higher storm intensity and therefore higher GIC levels. This provides a blended effort of model and observational data to extract details on how the same grid and ground strata would behave at higher storm intensity levels. One of the advantages that exists in the modeling of the circuits of the transmission networks are that the resistive impedances of transmission lines and transformers (which are the key GIC flow paths) are very well known and have small uncertainty errors. It is also known that the Chester transformer is non-auto, so GIC flow in the neutral also defines the GIC per phase. There is also no doubt about the locations of assets within the circuit topology. Finally, station grounding resistance can also be determined to relatively high certainty as well. In comparison, ground response as has been previously published in the Meta-R-319 report can vary over large ranges, as much as a factor of 6. Therefore direct observations of ground response are highly important and GIC measurements, as will be discussed, provide an excellent proxy or geophysical data that can be used to derive the complex behavior characteristics of the ground strata. This set of understandings can be applied as a tool to significantly bound this major area of uncertainty.

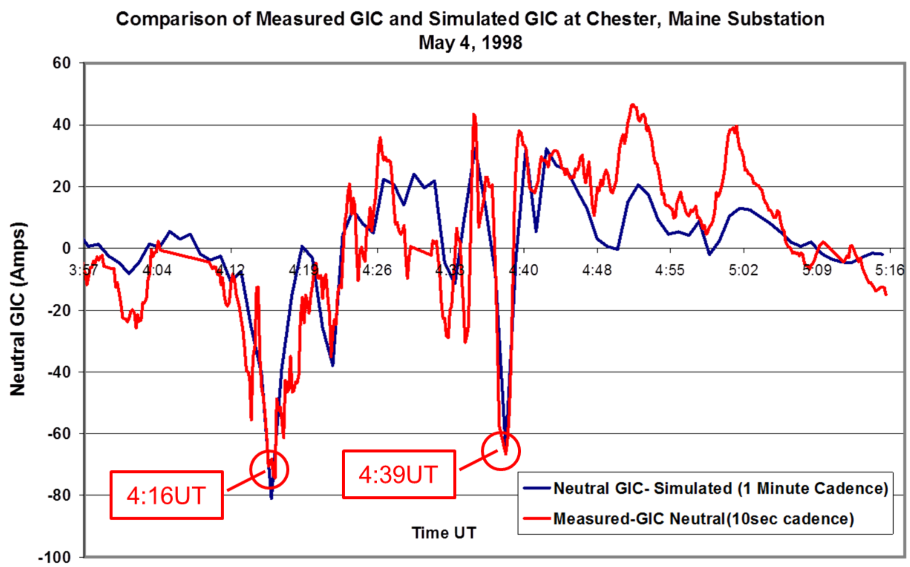

Figure 6 – GIC observation at times 4:16 & 4:39 UT that can be examined in further detail.

Network Model and Calculation of Chester GIC for 1 V/km Geo-Electric Field

Using the Maine region power grid model of the EHV grid, it is possible to examine what the GIC flow would be at the Chester transformer for a specified geo-electric field intensity of 1 V/km. This specified GIC is an intrinsic and precise characteristic of the network that will provide a useful yardstick to calibrate against for actual GIC flows that occurred and from that a more highly bounded geo-electric field intensity range can be determined at this location. Figure 7 provides a plot of the GIC flow in the Chester transformer for a 1 V/km geo-electric field. Since the topology of the transmission network also greatly determines the resulting GIC, this calculation is performed for a full 360 degree rotation of the orientation of the 1 V/km field.

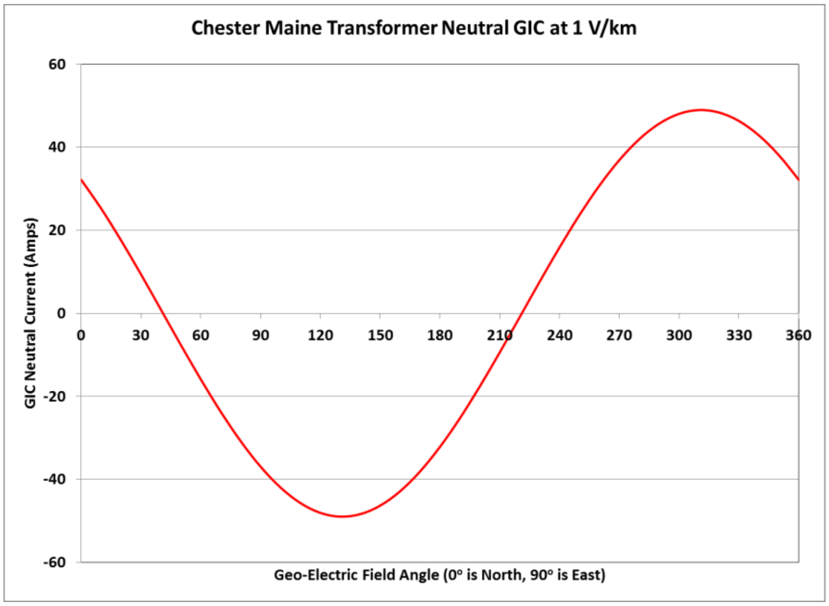

Figure 7 – GIC flow at Chester transformer neutral for 1 V/km geo-electric field at various orientation angles.

As the plot in Figure 7 shows, the peak GIC flow at this location is ~49 Amps which occurs at the 130° and 310° angular orientations of the 1 V/km field.

While the GIC to 1 V/km relationship in Figure 7 is developed from a detailed network model, there are also much simpler methods using a limited knowledge of a portion of the local transmission network that can be used to check the accuracy of the model. This involves a simple circuit analysis to derive the resistance and orientation specifics of just the two major transmission lines connecting to Chester. Each of the two 345kV lines connecting to Chester (from Chester-Orrington and from Chester to Keswick New Brunswick) is shown in the map of Figure 8.

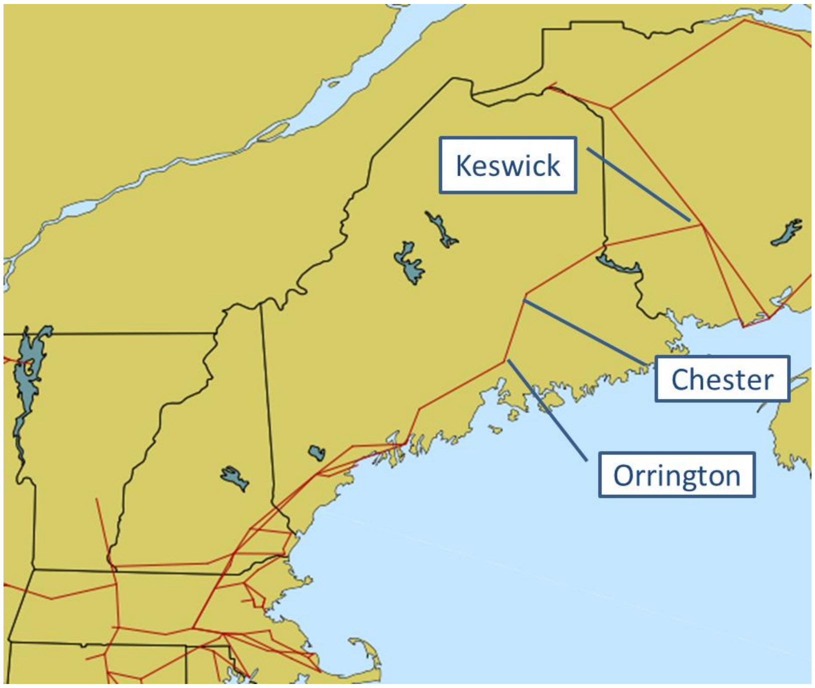

Figure 8 - Map of Chester Maine and 345kV line interconnections.

For geomagnetic storms, the orientation of specific transmission lines becomes very important in determining their coupling to the geo-electric field which also has a specific orientation. For example if the orientation of a specific line is identical to the orientation of the geo-electric field, then the GIC will be at a relative maximum. Conversely if the orientations of the field and line are orthogonal, then no coupling or GIC flow will occur. In the case of the Chester to Keswick line, the orientation is at an angle of ~70^o (with 0^o being North) and for the Chester to Orrington line the angle is ~205^o. Hence it should be expected that each line will couple differently as the orientation of the geo-electric field changes. Also an important parameter in the calculation of GIC is the line length which also describes the total resistance of this element of the GIC circuit. The point to point distances from Chester are ~80 km to Orrington and ~146 km to Keswick. Figure 9 provides the results of a simple single circuit calculation of the Chester transformer GIC connected to a 345kV transmission line of variable length with a transformer termination at the remote end of that line, the estimated GIC is also shown for the 80 km Orrington line and the 146 km Keswick line using a uniform 1 V/km geo-electric field strength. As shown in this figure, for the two line lengths only a small change in GIC occurs (~11%), even though there is nearly a factor of two difference in line lengths. This calculation assumes a full coupling with the orientation of the geo-electric field, as the geo-electric field changes its orientation to the line with time, and the GIC will change as prescribed via a sine function.

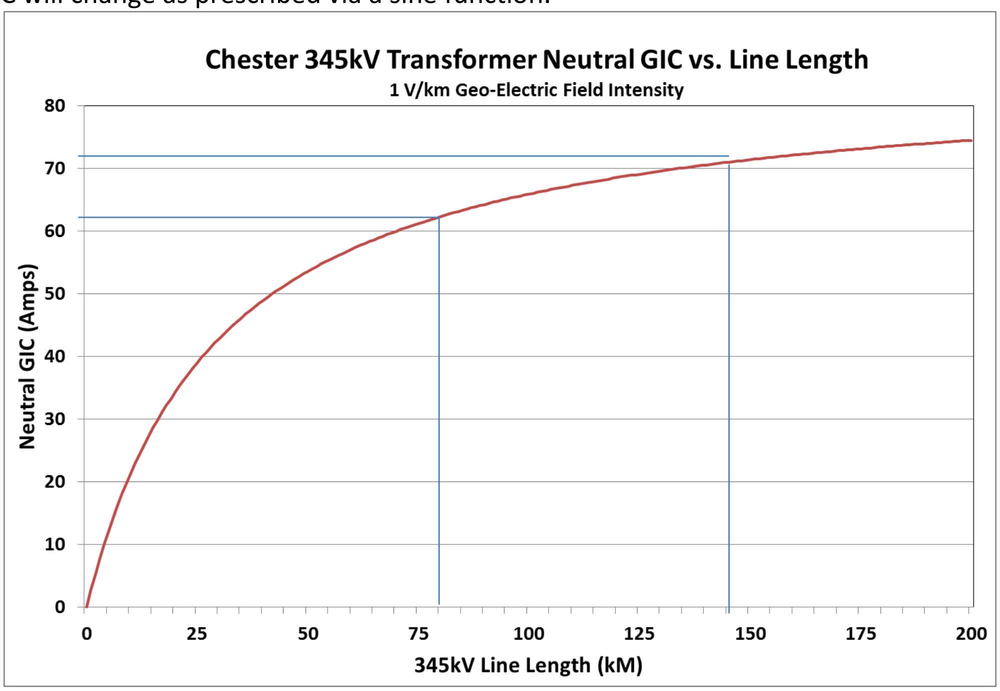

Figure 9 – Calculated Chester GIC for single circuit 345kV transmission line, 80 km Orrington and 146km Keswick noted

Given this simple two line case, a discrete calculation can be performed for each line, and using circuit superposition principles(Kirchoff's Laws), the resulting Chester GIC flow can be plotted as well versus the orientation angle of a uniform 1 V/km geo-electric field. This is shown in Figure 10 for each of the two lines and the resultant GIC flow at Chester.

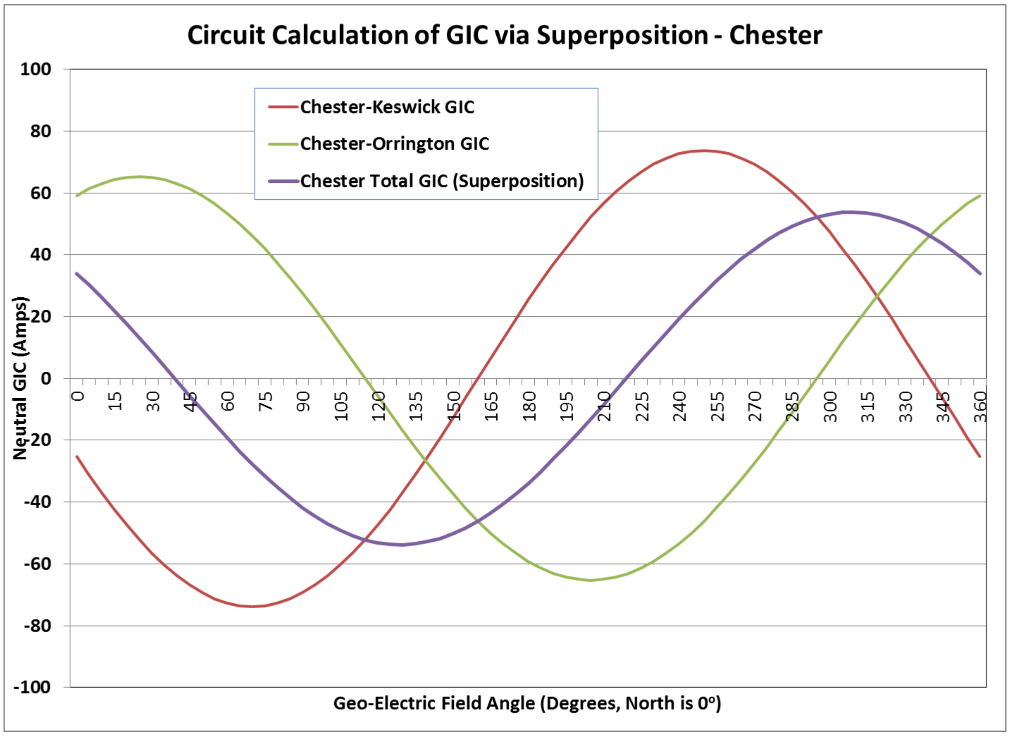

Figure 10 – GIC flow for each line versus geo-electric field angle and Resultant GIC at Chester.

Determining Storm Geo-Electric Field Intensity from Observed GIC

As this Figure 10 illustrates, each line segment will have differing GIC flows versus the orientation of the geo-electric field, and the resultant Chester neutral GIC will also be of lower magnitude and will also have a differing vector angle to each line segment. This simple Ohm's law based circuit calculation can be compared to the more detailed model calculation previously shown in Figure 7, which is shown in Figure 11. As this Figure illustrates, there is very good agreement in GIC flows using the two-line calculation approache (~95% agreement). The detailed model result will be more exact because all of the other network assets are used in the calculation. However, this comparison also shows that the line length parameter dominates the impedance of the circuit and defines the circuit current given the circuit resistances of just a few key components. Knowing both I (or GIC in this case) and R of the circuit allows the ability to precisely determine the driving V or geo-electric field that caused the observed GIC to occur in the transformer.

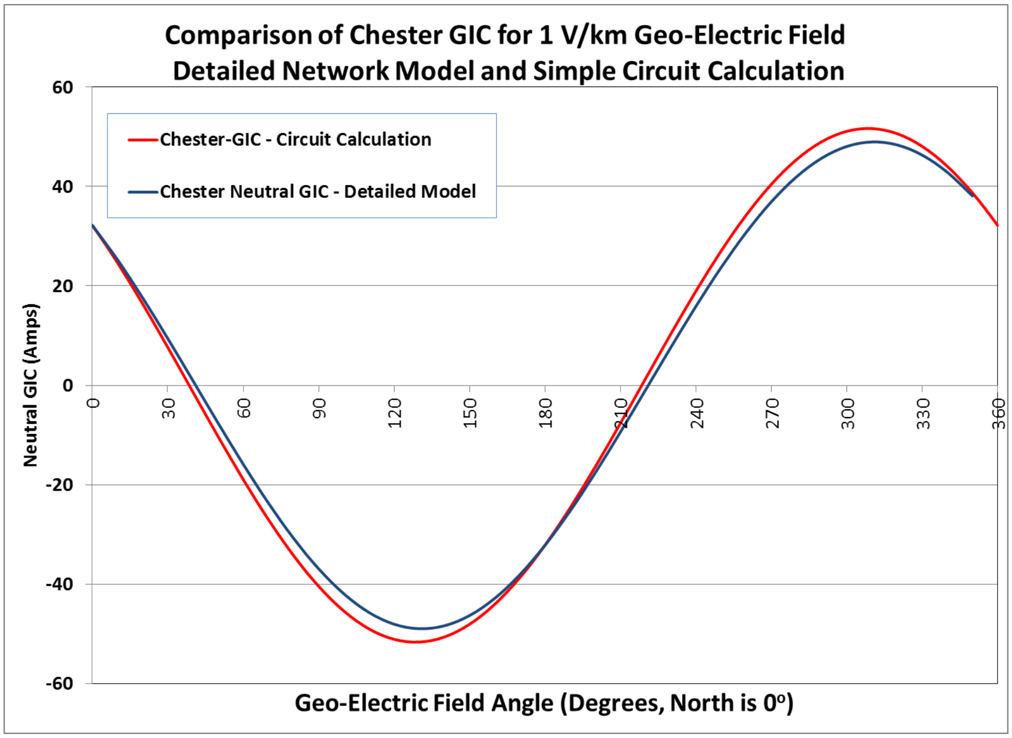

Figure 11 – Comparison of Calculated Chester GIC from detailed model and simple circuit calculation

Using the data from Figures 6 (the observed GIC at Chester) and Figure 11, it can be immediately inferred that the peak GIC levels of -66.6 and -74.3 Amps would have required a geo-electric field intensity of greater than 1 V/km to have occurred to produce such high levels of GIC. This is simply a process of utilizing Ohm's law knowledge to begin to develop an improved understanding of the geo-electric field intensity, an otherwise complex and uncertain field to calculate. In contrast it is not possible to infer the upper bound of geo-electric field, in that at angles where GIC nulls occur (such as 40^{o} and 220^{o}) even with a very high geo-electric field will not produce a significant GIC flow. As this point illustrates, these estimates can also be greatly improved by adding a simple understanding of geometry to this calculation. For example at time 4:16 UT, the simulation model results shown previously in Figure 3 illustrates a geo-electric field orientation at the Chester location which is almost exactly at 130^{o}, the orientation that would produce a peak GIC response at Chester. Using this circuit relationship of current to voltage allows extension to a scaling of the 49 Amp GIC at 1 V/km to a field intensity that would instead result in a 74.3 Amps GIC magnitude. This would lead to the estimated geo-electric field intensity at this 4:16UT time of ~1.5 V/km.

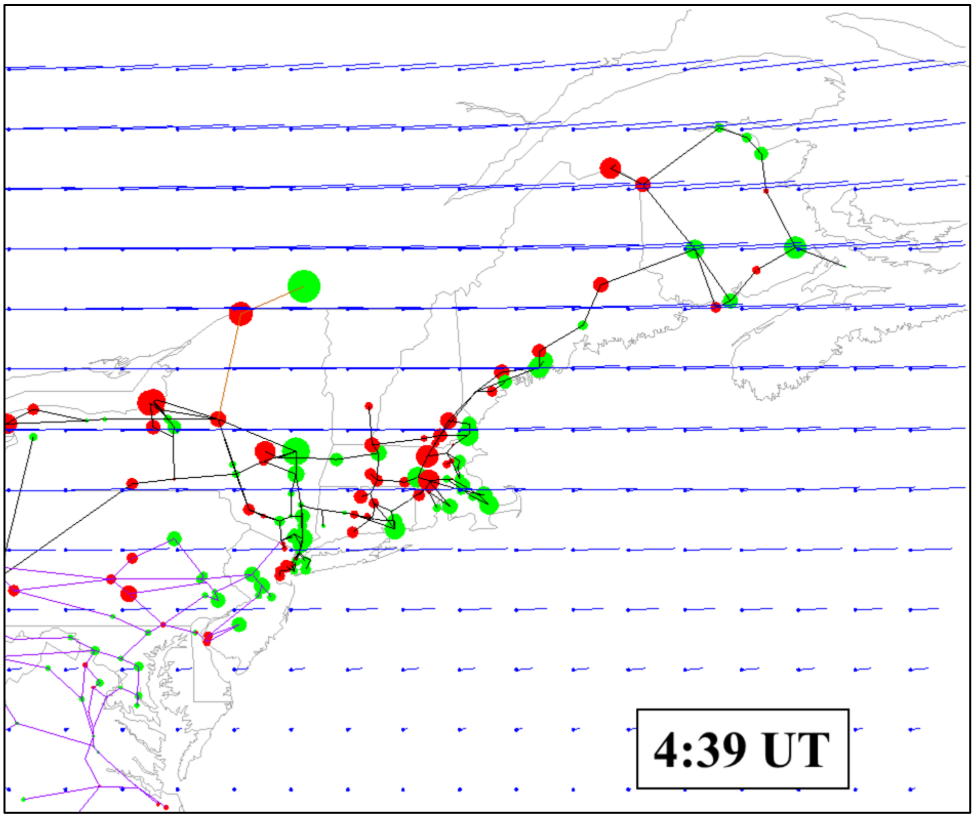

Figure 12 - GIC flows and disturbance conditions in Maine/New England grid at 4:39UT, May 4, 1998.

A similar simplified empirical analysis to confirm model results and expected geo-electric field levels can also be performed at time 4:39UT. Figure 12 provides a simulation output at time 4:39UT which again shows the intensity and geo-electric field angular orientation that would have occurred at this time step. This shows that the field was Eastward oriented or ~90^o. Since the characteristic GIC flows at Chester behave as a sine wave for variation of the geo-electric field angle to these circuit assets, a scaling factor based on these angular characteristics can also be applied, which would rerate the field to account for the less-optimal orientation angle at this time. In this case, the 66.6 Amp GIC would be produced by total geo-electric field of ~2 V/km, but only ~1.4 V/km of this total geo-electric field is utilized to produce a GIC flow in the Chester transformer. As this case illustrates, a higher total geo-electric field intensity occurred at 4:39UT than at time 4:16 UT, even though the GIC is lower at 4:39UT. This appears to be counter intuitive. However the event produced a smaller GIC, with the important difference being the angular orientation of the field alone.

As this example illustrates, the observation of GIC when properly placed in context provides an ability to develop an important metric for calculation of the driving geo-electric field that caused the GIC.

Validating the NERC Geo-Electric Field for Ottawa and New England Ground Models

As the previous discussion has revealed, the knowledge of GIC flows combined with the network resistance characteristics and locations of network assets can provide all of the information needed to fully resolve the storm Geo-Electric Field Intensity at any particular time during the storm. In other words knowing I and R allows the application of Ohm's law and geometry to derive V or the Geo-Electric Field. This means that GIC measurements can be utilized to derive the geo-electric field at all observation locations and provide important validations of the NERC Ground Models and Geo-Electric Field calculation methodology.

To better understand how GIC can be used to validate the NERC geo-electric field calculations, the regional nature and footprint of each storm needs to be more fully explained. Figure 13 provides a map of the Ottawa and St John's geomagnetic observatories and their proximity to the Chester substation in Maine. As this map illustrates, Chester is positioned in between these two observatories with Ottawa being ~550 km west of Chester and St. Johns being ~1230 km to the east of Chester.

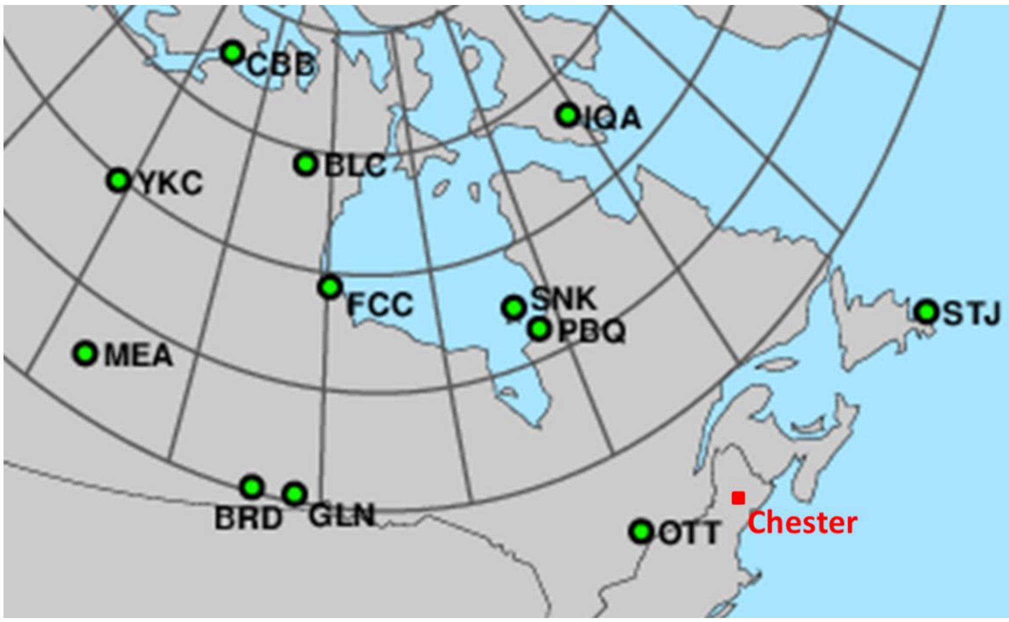

Figure 13 – Map showing Locations of Chester substation in comparison with Ottawa and St. Johns geomagnetic observatories

During the time period around 4:39UT which resulted in the peak GIC flow at Chester, both the Ottawa and St. John's geomagnetic observatory also recorded similar impulsive disturbance levels. This plot of these two observatories is shown in Figure 14. Because both of these observatories recorded this same coherent impulsive disturbance, this suggests that the observations had to be connected to the same coherent ionospheric electrojet current structure (in this case an intensification of the Westward Electojet Current) that would have extended all the way between these observatories and directly in proximity to Chester, Maine as well.

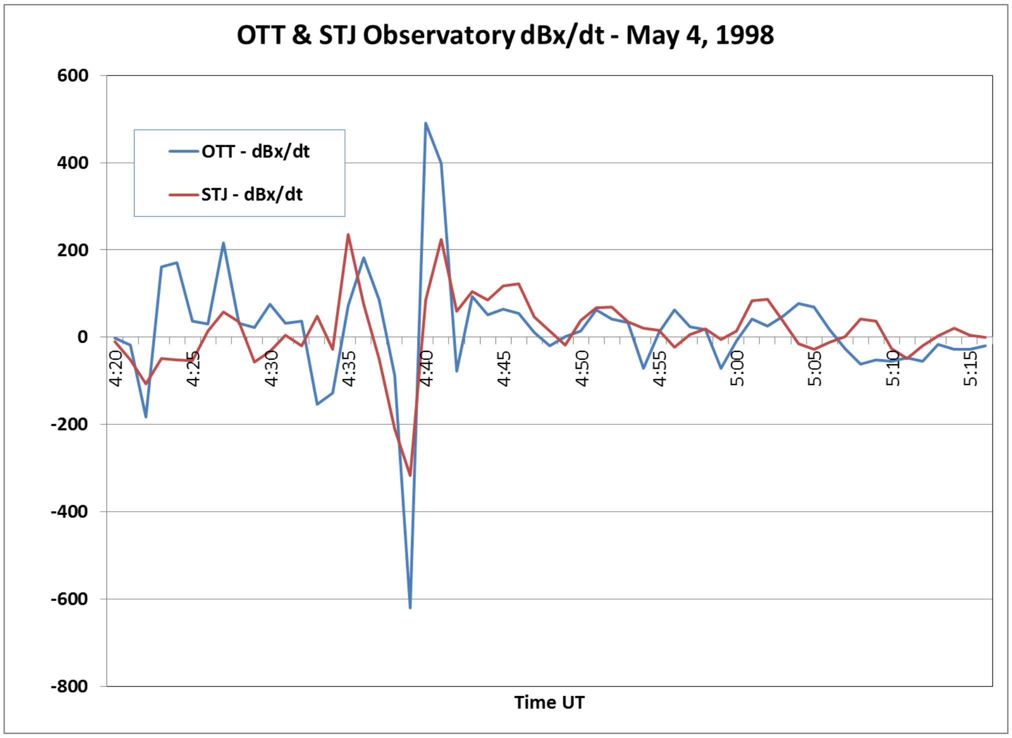

Figure 14 – Observed Impulsive disturbance at Ottawa and St. John's on May 4, 1998 at time 4:39UT.

At Chester some limited 10 second cadence magnetometer data was also observed during this storm, and Figure 15 provides a plot of the delta Bx at Ottawa (1 minute data) compared with the Chester delta Bx (10 sec) during the electrojet intensification at time 4:39UT. As this comparison illustrates that at this critical time in the storm, the disturbances at both Ottawa and Chester were nearly identical in intensity.

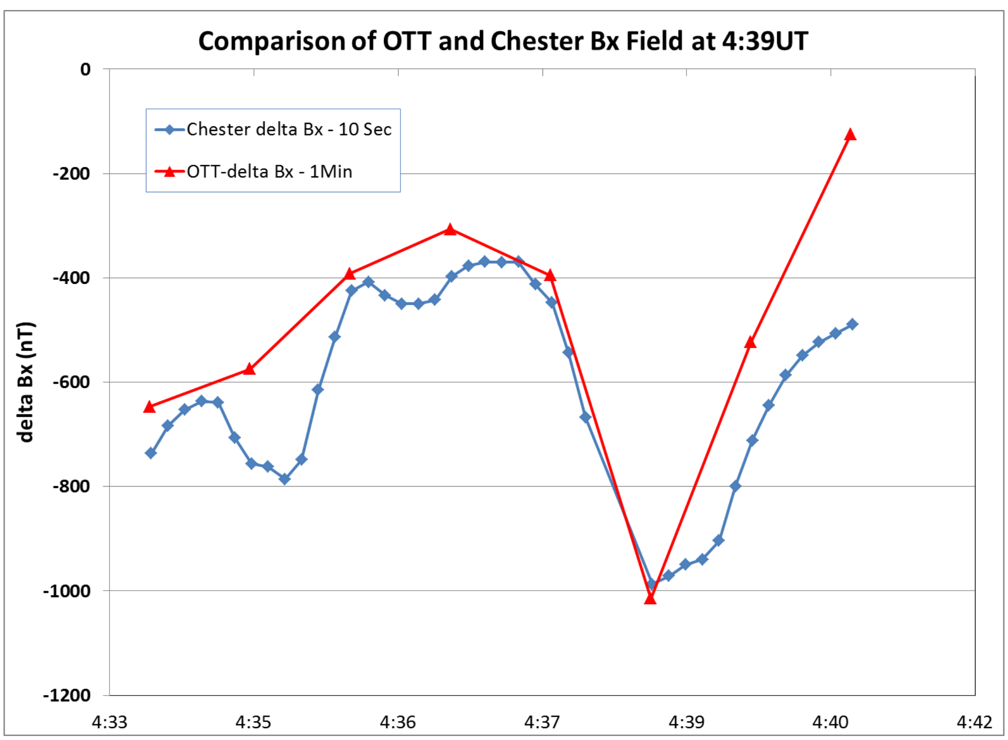

Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.

This close agreement between the observations at Ottawa and at Chester therefore allows the comparison of geo-electric field estimates between these two sites to be compared. As we had previously established using Ohm's Law, the peak geo-electric field must reach ~2 V/km to create the level of GIC observed during this storm. Geo-electric field calculations using a simulation model developed by the NERC GMD Task Force can be compared with the simulated geo-electric field in the Metatech simulation[4]. This comparison is shown in Figure 16. In addition, several portions of this geo-electric field waveform comparison are noted.

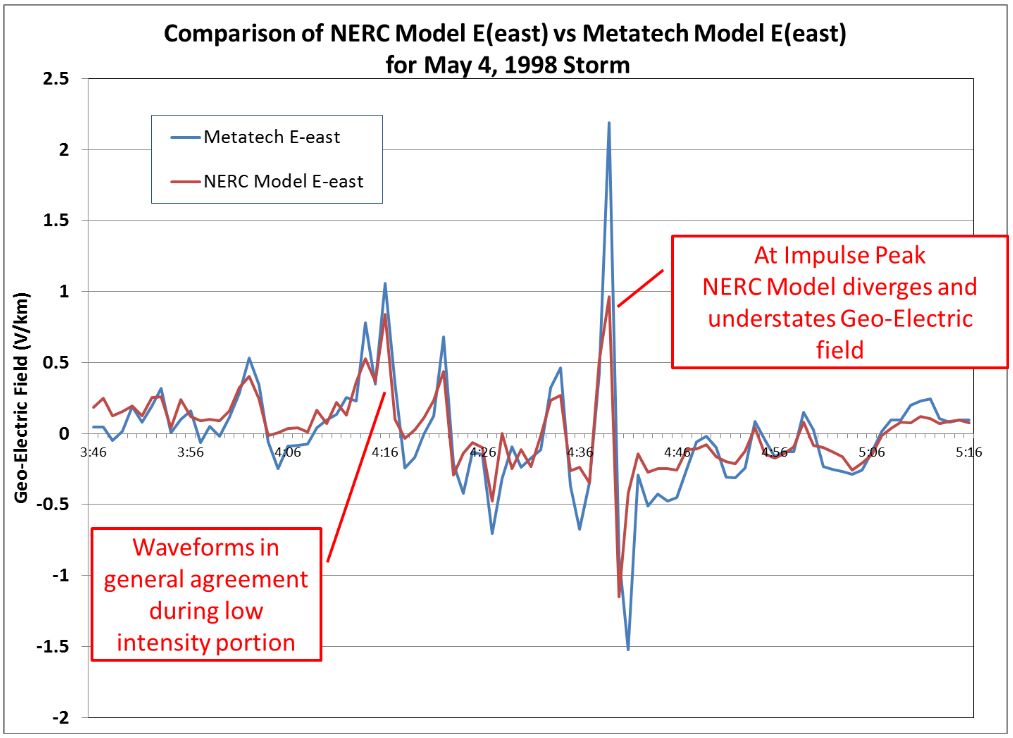

Figure 16 – Comparison of Metatech east-west geo-electric field calculation and NERC east-west geo-electric field calculation for May 4, 1998 storm event.

In the earlier portions of the storm simulation, the relative agreement between the two models for the geo-electric field is quite close. This occurs during a quieter and less intense portion of the storm. However as shown at the large impulse around time 4:39 UT, there is a divergence of agreement between the two models with the NERC modeling method understating the Metatech model results by a significant margin. After that impulse is over, the two models again come into relatively close agreement again. This suggests a problem in the NERC model of understating the intensity for more intense impulsive disturbances. As previously shown, the intensity in dB/dt is ~600 nT/min at time 4:39 UT, while it is generally below 100 to 200 nT/min at all other times during the simulation. Hence this higher intensity may be an important inflexion threshold within the NERC model.

As previously discussed Ohm's Law requires a sufficiently large enough geo-electric field to create the GIC flow observed at this location. Using the NERC model geo-electric fields it is possible to calculate the GIC flow and compare this to the GIC flow calculated for the Metatech model and even to the observed GIC. Figure 17 provides a comparison of the NERC model GIC with that computed in the

[4] Geo-elctric field data for this storm downloaded from NRCan http://www.spaceweather.gc.ca/data-donnee/dl/dl-eng.php#view

Metatech model. Figure 18 compares the same NERC Model GIC result with actual GIC observed at Chester. As both of these figures illustrate, the NERC model results will under predict the GIC at the peak storm intensities. In the case of the peak at time 4:39UT the understatement was similar in both the model comparisons and the observed GIC comparison.

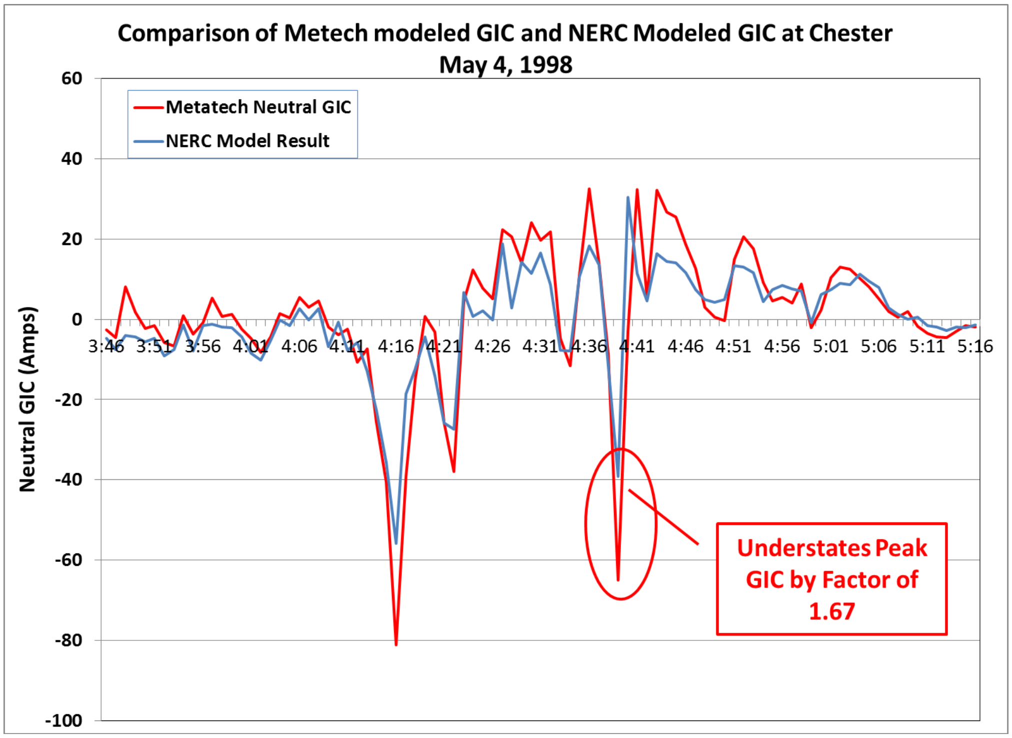

Figure 17 – Comparison of Metatech model GIC to NERC model GIC at Chester.

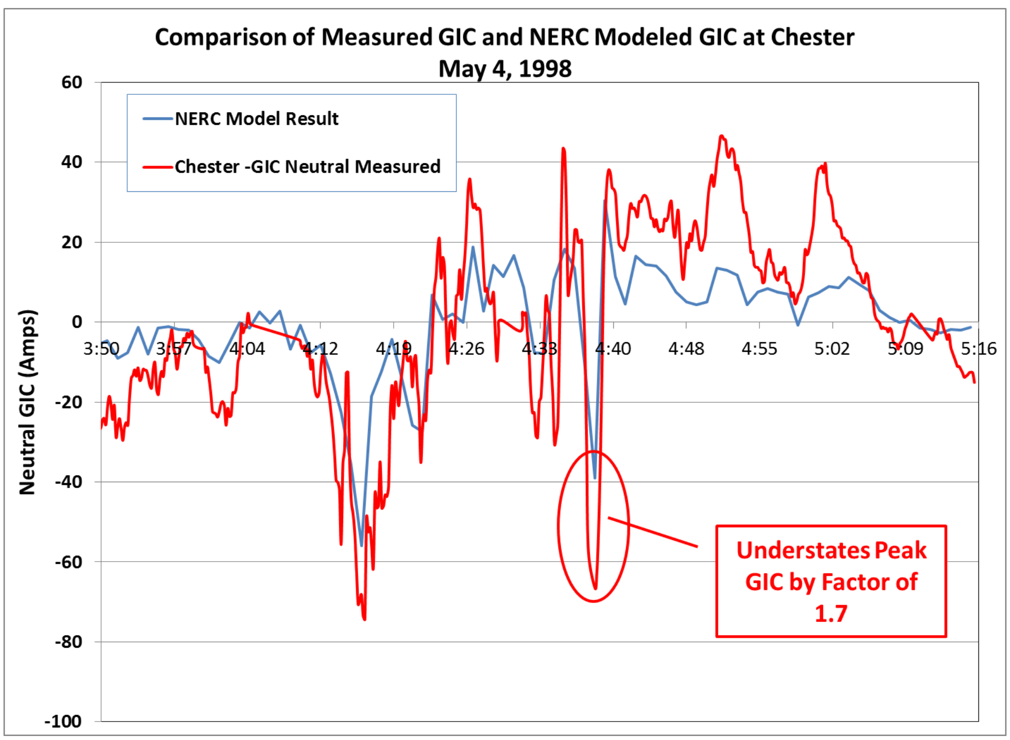

Figure 18 - Comparison of NERC model GIC to observed GIC at Chester.

NERC Model Validation Problems and Other GIC Observations

Seabrook GIC Observations July 13-16, 2012

While a number of GIC observations have been made over the last few decades in the US, very little of this information has been made publicly available. However where there is public information, it is possible to examine that data in a similar manner to the observations in Chester. Last year, observations as provided in Figure 19 were reported for GIC observations at the Seabrook Nuclear Plant[5]. These observations indicated peak GIC intensities during this storm that reached levels of 30 to 40 amps several times during the storm. The peak of 40 Amps occurred on July 16, 2012.

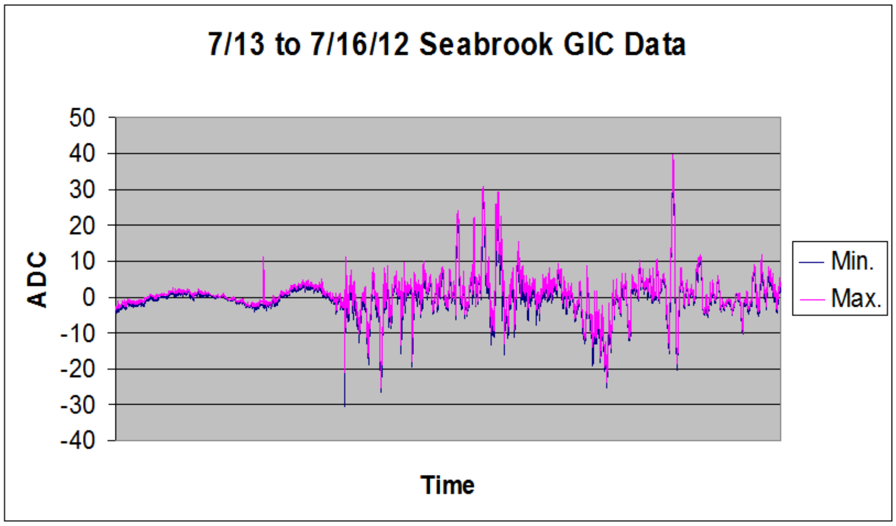

Figure 19 – GIC Observations at Seabrook Nuclear Plant July 13-16, 2012

Seabrook is also located in the New England region and because it is a GSU transformer, the neutral GIC also determines the flow that injects into the 345kV transmission network in that region. Figure 20 provides a map showing the location of Seabrook, and like Chester it will be heavily influenced by the same storm processes that will be observed at the nearby Ottawa observatory. In fact Seabrook is even closer to Ottawa than Chester.

[5] Geomagnetic Disturbance Mitigation for Nuclear Generator Main Power Transformers, Kenneth R. Fleischer, Presented April 16, 20132 at NOAA Space Weather Week Conference, Boulder Co.

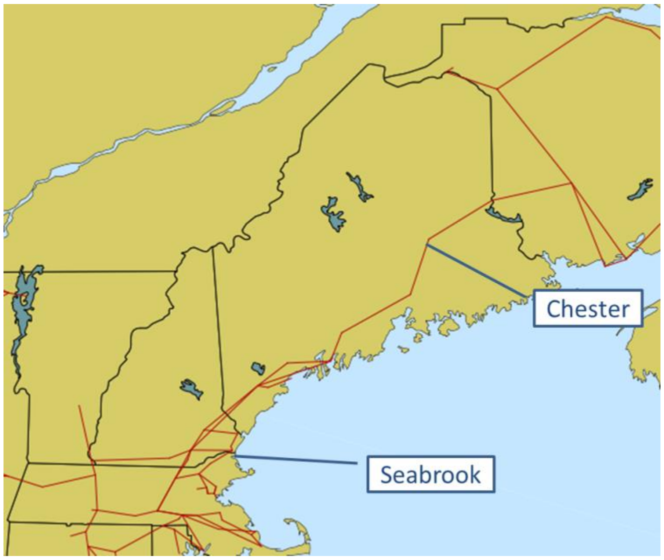

Figure 20 – Location of Seabrook Nuclear Plant in New England region 345kV network.

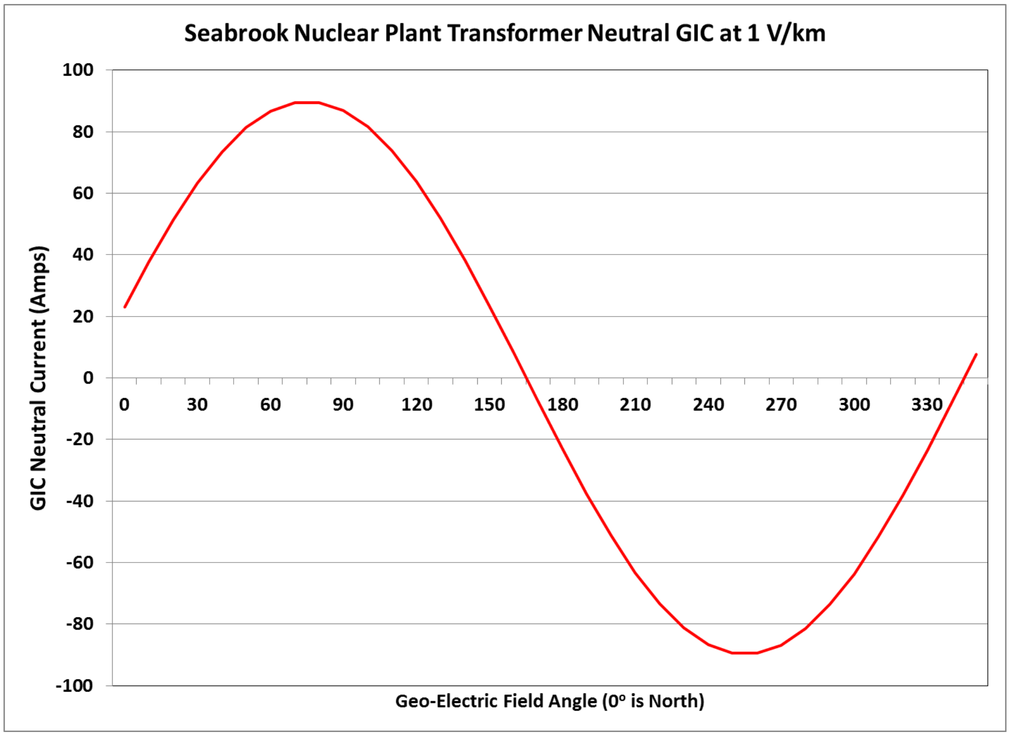

Figure 21 - GIC flow at Seabrook transformer neutral for 1 V/km geo-electric field at various orientation angles.

Figure 21 provides a plot of the characteristic GIC flows that would be observed at Seabrook for a uniform 1 V/km geo-electric field for a 360 degree rotation. This is computed similar to the way it was done at Chester. At this location, a 1 V/km geo-electric field produces ~90 Amp GIC at an 80^{o} angle (essentially nearly east-west oriented). Compared to the characteristic GIC plot for Chester (Figures 7 and 11), for a 1 V/km geo-electric field at Seabrook the GIC will be ~50% higher. This is due to the more integrated connections at Seabrook into the New England 345kV grid and lower circuit impedances, as would be expected. This characteristic indicates that for the 40 Amp GIC observation that occurred on July 16, 2012, there must have been a net east-west geo-electric field of ~0.45 V/km to produce this large of a GIC, a requirement dictated by the Ohm's law behavior of the circuit at Seabrook.

Figure 22 provides a plot of the East-West Geo-Electric Field that would be derived using the NERC model from this storm, using the Ottawa observatory geomagnetic field disturbance conditions as the input. As shown the peak field intensity reaches only ~0.1 V/km which is ~4 times too low to produce the actual GIC observed at Seabrook for this storm event. Hence this storm simulation model provides an example of even worse GIC validation attempt than at Chester. (Not shown is that the peak north-south geo-electric field would have been ~0.12 V/km. But these are also too low and would not couple efficiently with the Seabrook region circuits; therefore this was not a factor in the GIC levels at Seabrook.)

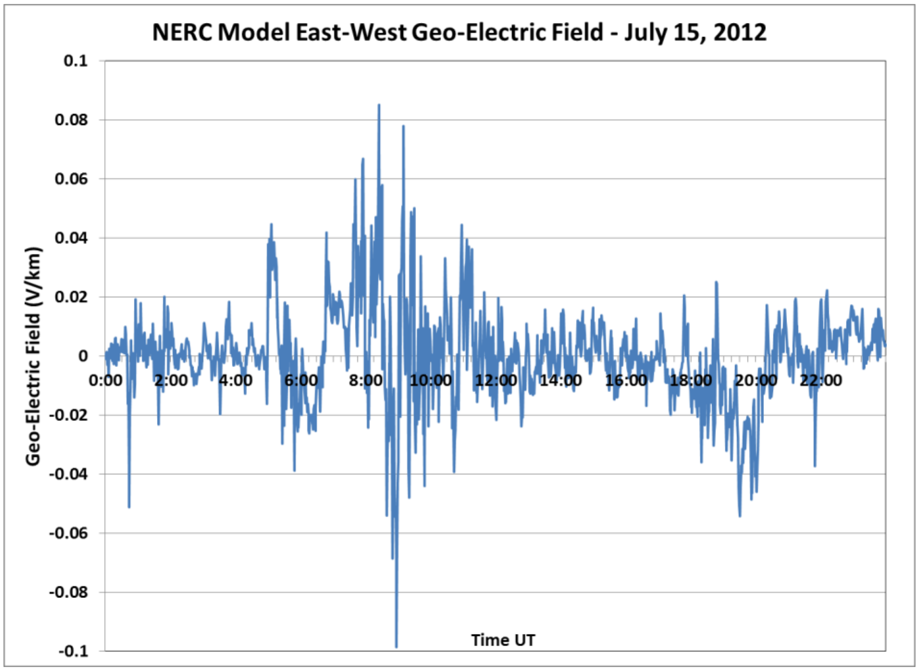

Figure 22 – NERC Model estimated East-West Geo-Electric Field on July 15, 2012 for the NE1 ground model.

BPA Tillamook GIC Observations Oct 30, 2003

In another situation, an examination has been conducted for ground models in the Pacific northwest region of the US. Data on GIC observations in the BPA transmission system have been provided to the Resilient Society Foundation under FOIA provisions and have been provided for analysis and ground model validation purposes. The GIC observations at the BPA Tillamook 230kV substation are examined in this case study. The Tillamook substation is on the western end of the BPA transmission network as shown in the map in Figure 23. There is a single 230kV line from Tillamook to the Carlton substation, but also 3 115kV lines that also connect at Tillamook, two which go in mostly North-South directions and one that connects to the East at Keeler.

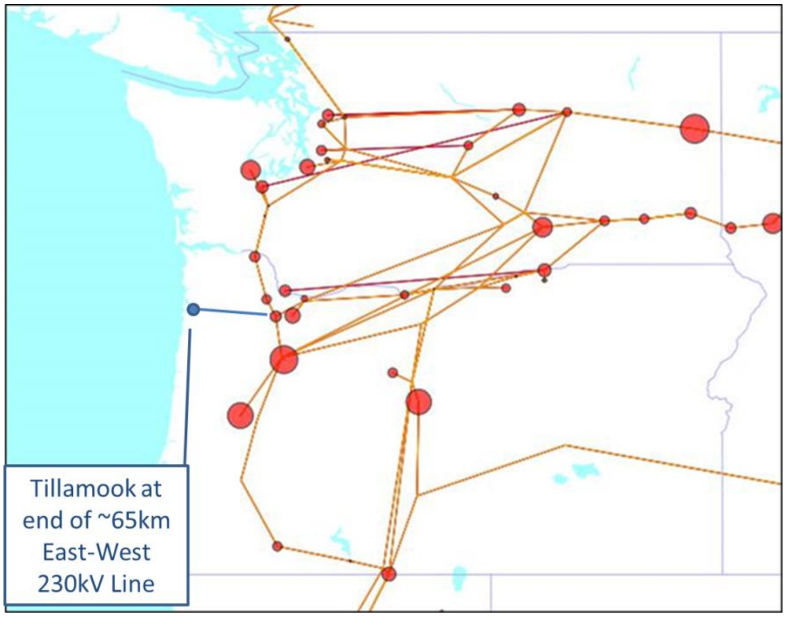

Figure 23 – Map of Tillamook 230kV substation and BPA 500kV network

Figure 24 provides a set of observations of GIC over a 2 hour time period at Tillamook which BPA provided in both 5 minute average and 2 second cadences during the October 30, 2003 storm. As shown in the 2 sec cadence data, the peak GIC approached nearly 50 Amps around time 19:55UT.

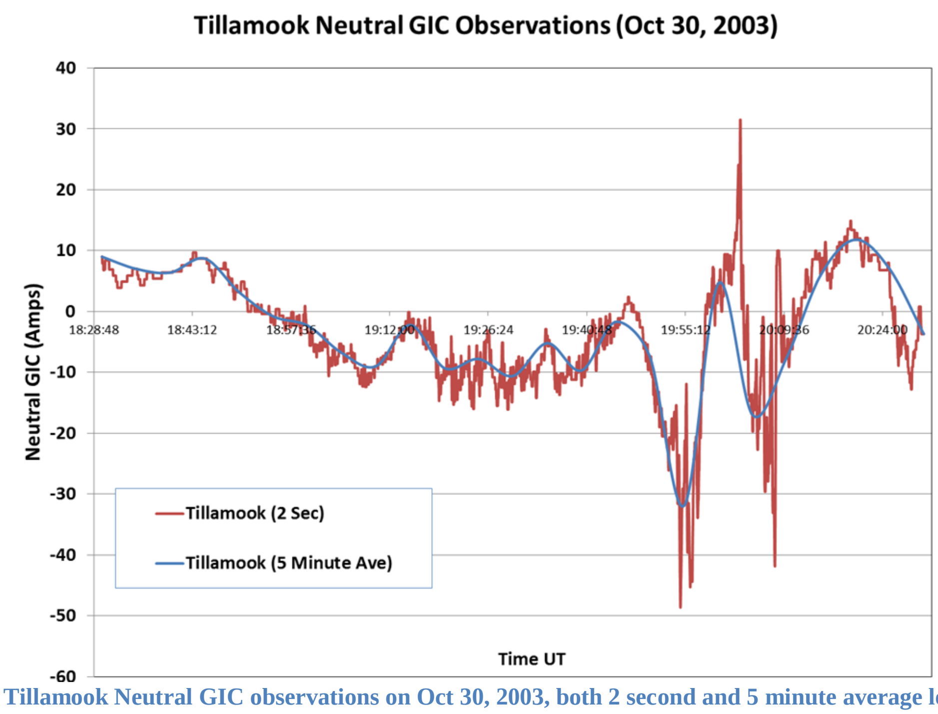

Figure 24 – Tillamook Neutral GIC observations on Oct 30, 2003, both 2 second and 5 minute average levels are shown

The Oct 30, 2003 storm conditions around time 19:55 UT are summarized from regional geomagnetic observatories as shown in Figure 25. This summary indicates that a region of intensification did encroach down into the Tillamook proximity at this time and would have been responsible for the peak GIC flows observed at this time, though Tillamook was not exposed to the worst case storm intensities.

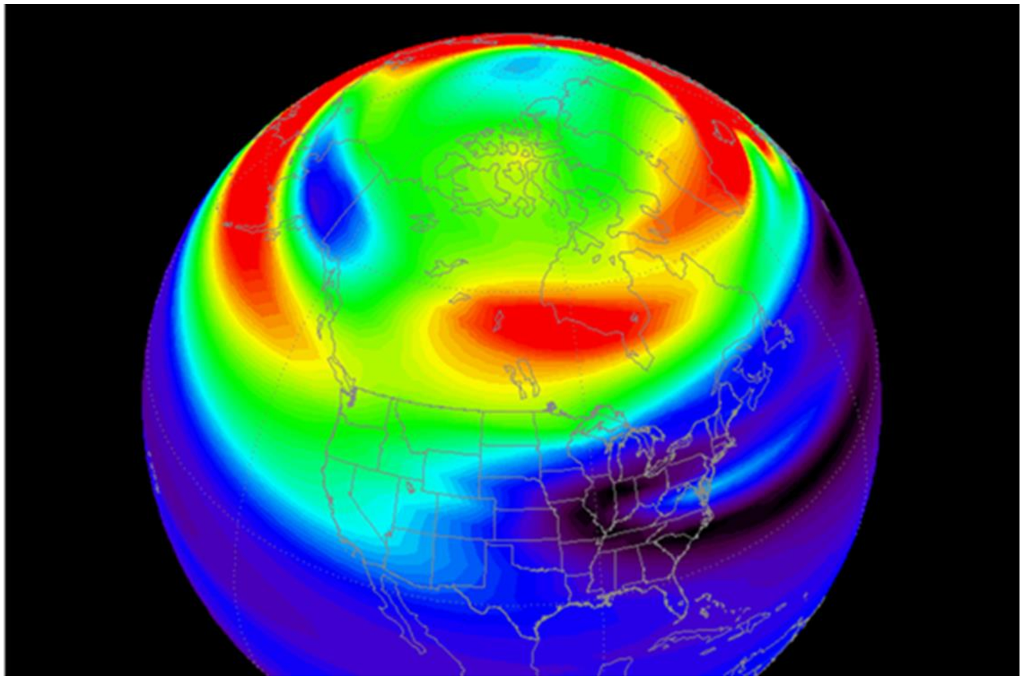

Figure 25 – Regional storm conditions at time 19:55UT October 30, 2003 at time of peak Tillamook GIC flows

Using methods similar to those developed for the Chester station and the various BPA physical data sources available, the characteristic GIC flows for the Tillamook 230kV autotransformer can be calculated for a rotated 1 V/km geo-electric field. The results for this are shown in Figure 26 and the peak GIC reaches a level of ~38 Amps for a predominantly east-west oriented geo-electric field. Therefore when examining the GIC levels observed at Tillamook on Oct 30, 2003, Ohm's law would constrain that the minimum geo-electric field in this region would need to exceed 1 V/km (in at least the east-west direction) to produce the nearly 50 Amps GIC peaks.

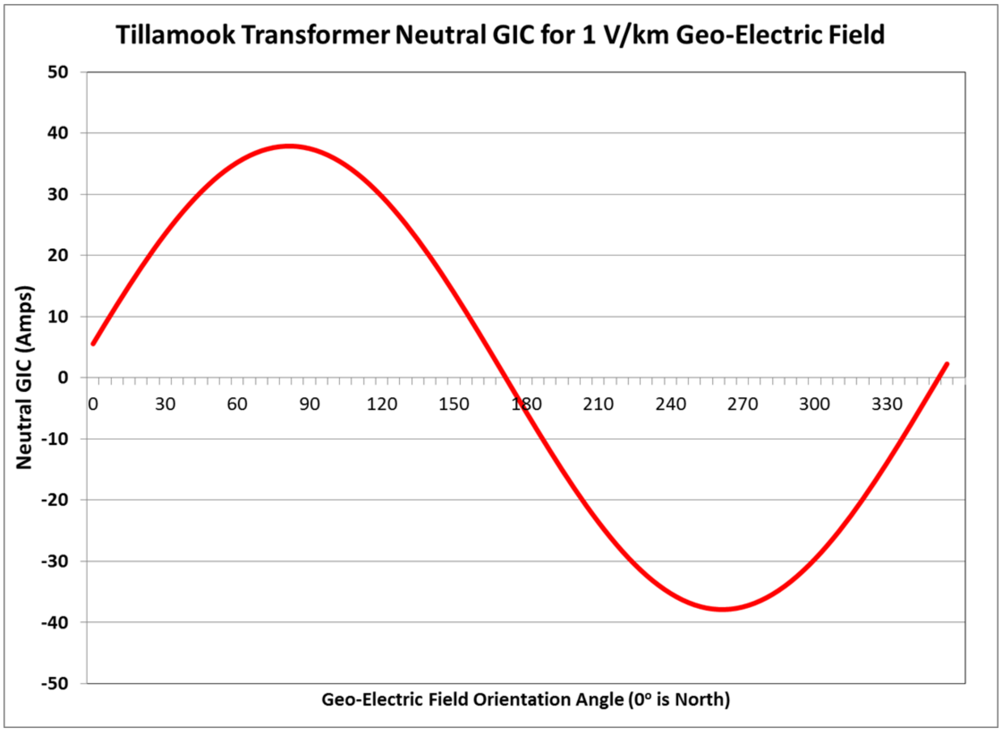

Figure 26 - GIC flow at Tillamook transformer neutral for 1 V/km geo-electric field at various orientation angles.

The NERC model calculations for East-West geo-electric field using the PB1 model are shown in Figure 27 for the same time interval as shown in Figure 24 for the Tillamook high GIC observations, but since the Tillamook GIC flow characteristics are defined in Figure 26, it is possible to utilize this to derive the minimum East-West geo-electric field responsible for producing the GIC flows in Figure 24. These results are also presented in Figure 27 with the NERC model predictions for this storm.

As Figure 27 shows, the peak geo-electric field as strictly constrained by Ohm's law must exceed 1 V/km during portions of the GIC flow where the Tillamook GIC exceeded ~38 amps level. At all times, the NERC model geo-electric field did not exceed even 0.25 V/km. As this comparison illustrates, the NERC model greatly understates the peak geo-electric field intensities at the peak GIC flow portions of the storm. In some cases this understatement is more than a factor of 4 to 5 times too small. This degree of divergence is also worse than what was observed at Chester Maine and is similar to the error level noted for Seabrook.

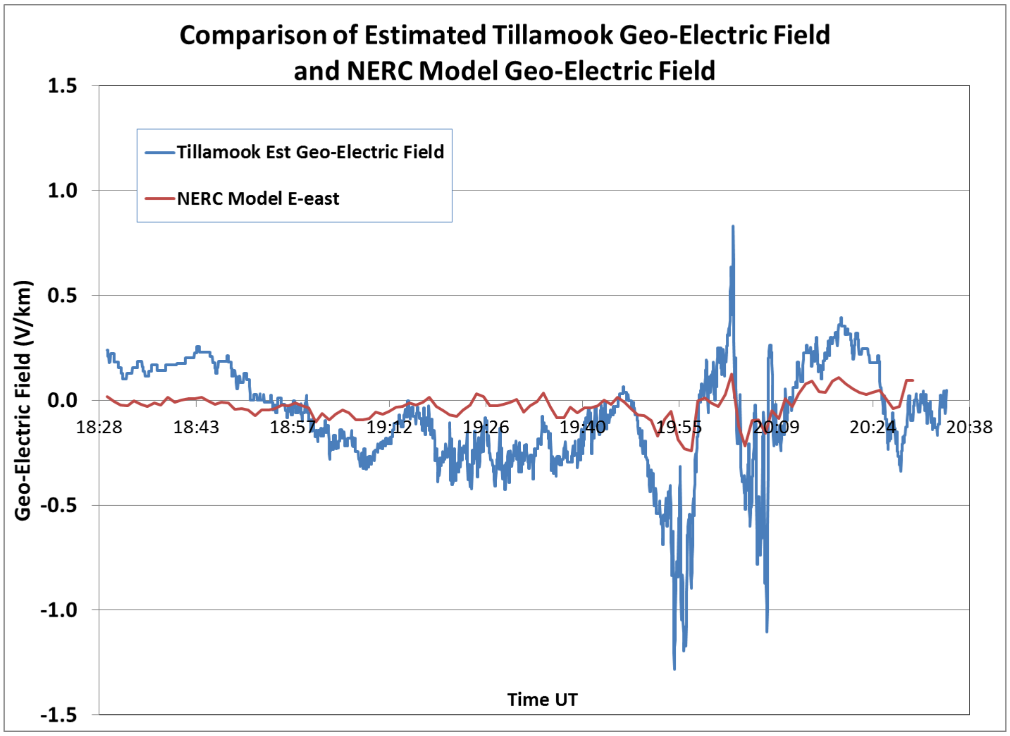

Figure 27 – Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the Oct 30, 2003 storm

There are other storms available with similar levels of GIC measurements observed at the Tillamook substation and 230kV line. Because this 230kV line is an East-West orientated line, GIC observed there will be largely driven by North-South variations (or dBx/dt) in the geo-magnetic field which subsequently produces an East-West geo-electric field. Figure 28 provides a plot of the nearest geomagnetic observatory (Victoria, ~340 km north of Tillamook) and the Tillamook GIC observed during an important storm on July 15-16, 2000. These geomagnetic disturbance conditions reach a peak of just over 150 nT/min resulting in GIC flows (5 min averaging) reaching -43.5 Amps at time 20:25UT. Figure 29 provides a detailed regional summary which show the more global storm conditions that were occurring at time 20:25UT over North America. As this Figure illustrates, the most severe storm conditions were located quite far to the North, so the GIC observed for these conditions could have been driven to much higher levels had the intensity extended further southward.

From the GIC observations for this storm, the minimal Geo-Electric field levels necessary to produce the GIC flows observed at Tillamook can be again calculated. This can also again be compared with the estimates used by NERC in modeling this storm event, this comparison is shown in Figure 30. In the comparison of the NERC model geo-electric field with the actual geo-electric field as derived from GIC measurements, the NERC model again greatly under predicts peak V/km intensities, by as much as a factor of ~5 or more at peak intensities times. These results are similar to the results from the Oct 30, 2003 storm as shown in Figure 27 and further confirm that the NERC models will not accurately depict storm conditions.

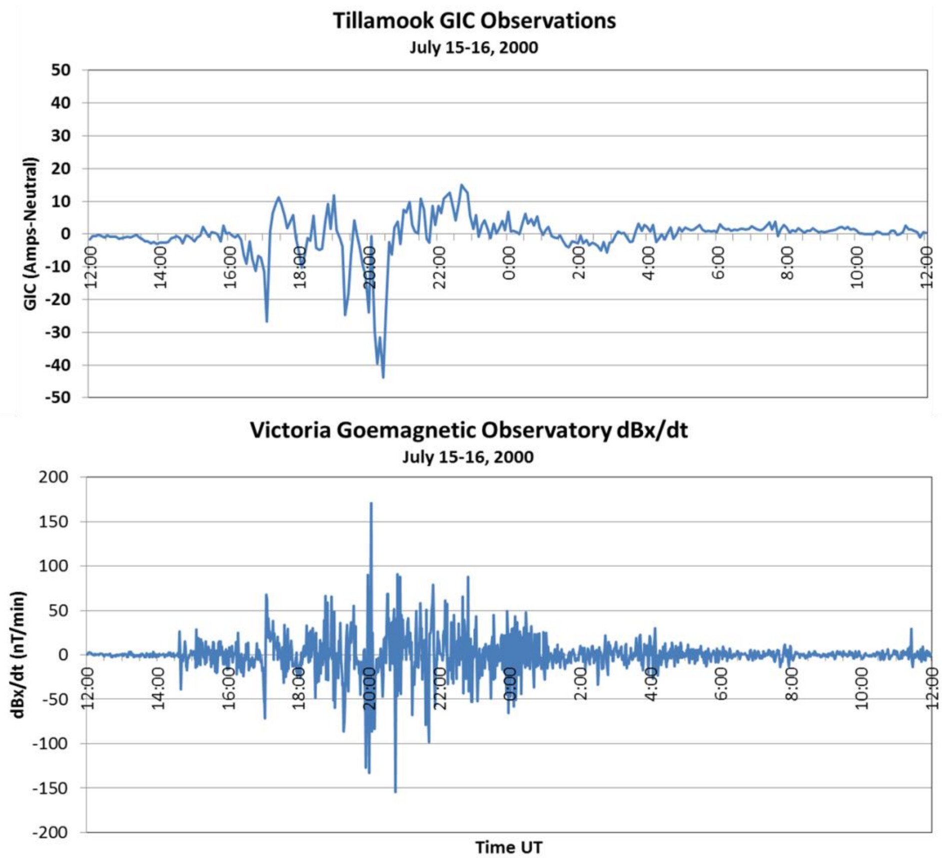

Figure 28 – Observed Tillamook GIC and Victoria dBx/dt for storm on July 15-16, 2000.

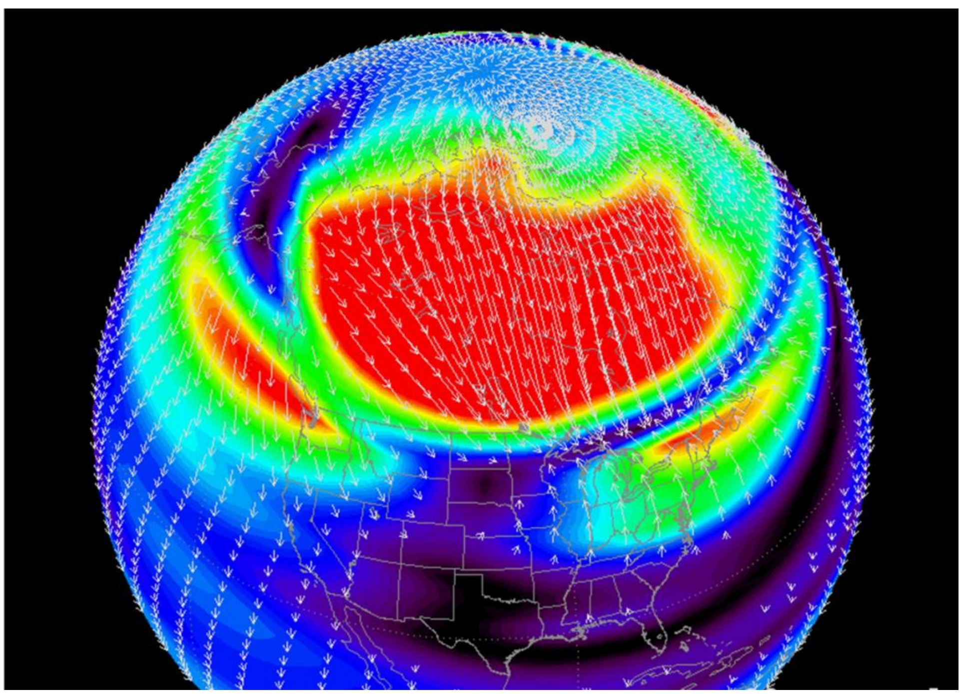

Figure 29 - July 15, 2000 at time 20:25UT storm conditions at time of Tillamook -43.5 Amp GIC Peak.

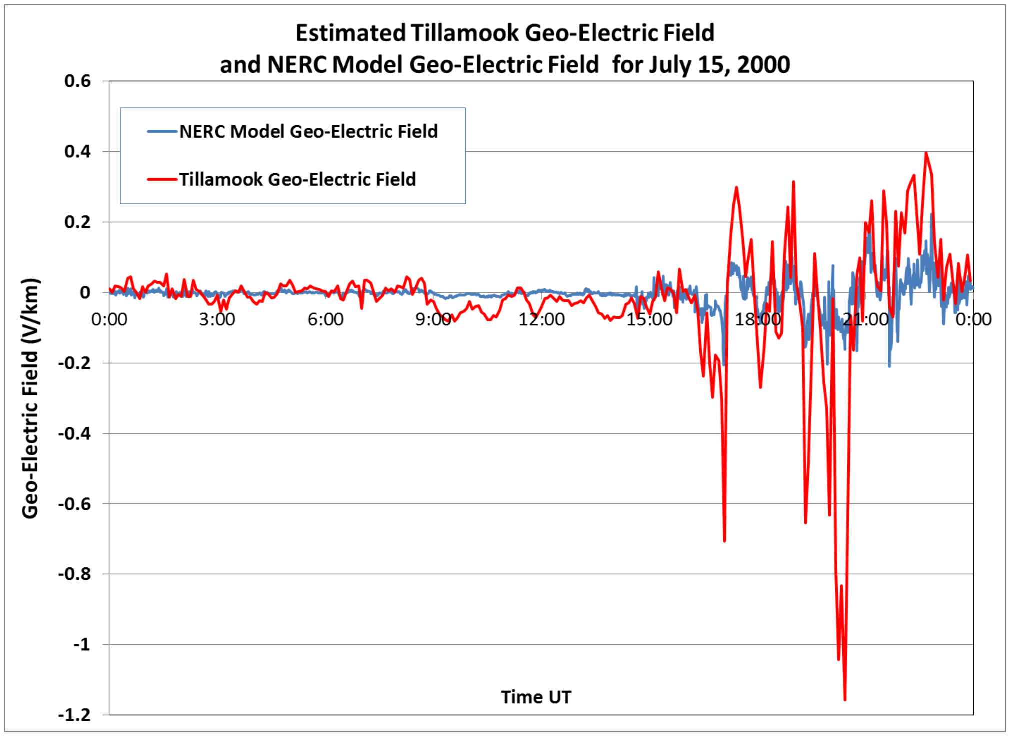

Figure 30 - Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the July 15, 2000 storm

Other Instances of Geo-Electric Field Modeling Concerns

The NERC geo-electric field simulation tools had their genesis out of the Finnish Meteorology Institute and have since been adopted at NASA (A. Pulkkinen) and also at Natural Resources Canada and many other locations around the world. Pulkkinen in particular was a key NERC GMD Task Force science investigator, a key EPRI science investigator along with staff from NRCan. Pulkkinen was also a member of the NERC GMD Standards Task Force, where the draft standards incorporating these tool sets are fully integrated into the science analysis and are recommended tools for system analysis. In the entirety of the NERC GMD task force investigations, no evidence has been made available by the NERC GMD Task Force of rigorous validations of the suite of ground models and derived relationships that have been published. USGS scientist involved in the effort asked for more power industry efforts to do model validations at several NERC GMD meetings, with no active participants and no subsequent publications supporting the ability to verify these models.

These FMI/NRCan-based geo-electric field modeling approaches use a Fourier transform method[6]. Fourier transforms are well-conditioned for periodic signals, not the very aperiodic events associated with abrupt, high intensity impulsive disturbances typical for severe geomagnetic storms. Therefore a Fourier approach needs to be carefully considered and tested rigorously to assure fidelity in output resolution for severe impulsive geomagnetic field disturbances. An additional geo-electric field modeling approach has been developed by Luis Marti based upon Recursive Convolution[7]. Unfortunately no independent validation for this model was noted in their IEEE paper on the model, rather it was only

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[6] How to Calculate Electric Fields to Determine Geomagnetically-Induced Currents. EPRI, Palo Alto, CA: 2013. 3002002149.

[7] Calculation of Induced Electric Field During a Geomagnetic Storm Using Recursive Convolution, Luis Marti, A. Rezaei-Zare, and D. Boteler, IEEE TRANSACTIONS ON POWER DELIVERY, VOL. 29, NO. 2, APRIL 2014

tuned to agree with the FMI/NRCan geo-electric field model output results. In addition, staff from the NOAA SWPC and USGS were also provided tool sets that were tuned to the NASA-CCMC/NRCan geo-electric field models so that the results that each examined would be the same. Hence no real independent assessments were ever apparently undertaken by all of these organizations. Therefore all of the various NERC GMD models appear to produce results that will consistently understate the true geo-electric field intensity.

In looking at recent publications by Pulkkinen, et. al., a paper titled "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden"[8] was published in the Space Weather Journal in 2008. In this paper the authors presented results from several storm events that were similar in intensity to the May 4, 1998 storm that was discussed in a prior section of this report. Figure 31 is a set of plots from Figure 7 of their paper showing the disturbance intensity (dB/dt in nT/min) in the bottom plot and the measured and calculated GIC in the top plot. As illustrated in this Figure, the storm intensity is similar to that experienced in Maine during the May 4, 1998 storm at ~500 nT/min. In regards to the comparison of the Measured and Calculated GIC the simulation model greatly under predicts the actual measured GIC during the most intense portion of the storm around hour 23 UT by substantial margins (factor of 3 or more). This is the same symptomatic outcome observed in the NERC model results and provides another independent assessment with possible inherent problems with this modeling approach.

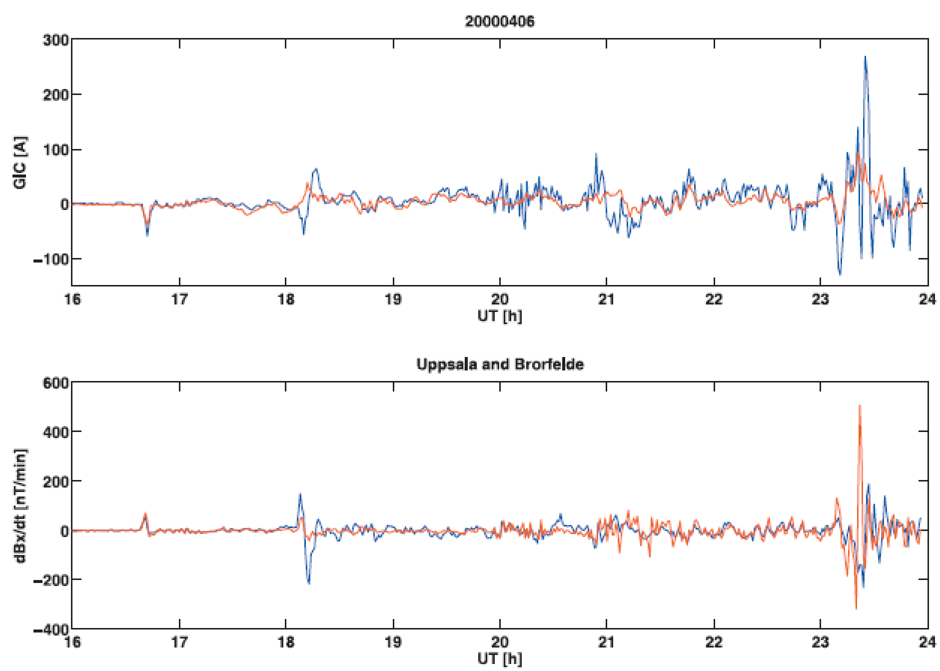

Figure 7. The top curve shows the measured (blue) and calculated (red) GIC at Simpevarp-2 (6 April 2000). The bottom curve shows dB_x/dt from Uppsala (blue) and Brorfelde (red).

Figure 31 – Plot Figure 7 from Pulkkinen, et.al.,paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing storm intensity and GIC comparisons

[8] Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden, M. Wik, A. Viljanen, R. Pirjola, A. Pulkkinen, P. Wintoft, and H. Lundstedt, SPACE WEATHER, VOL. 6, S07005, doi:10.1029/2007SW000343, 2008

In another example from this same paper, a figure shown below as Figure 32 provides a comparison plot of the Measured and Calculated GIC during the July 15, 2000 storm at the same transformer in southern Sweden. The GIC results as in all prior comparisons greatly diverge during the occurrence of the largest and most sudden impulsive disturbance events, such as those between 21 and 22 UT.

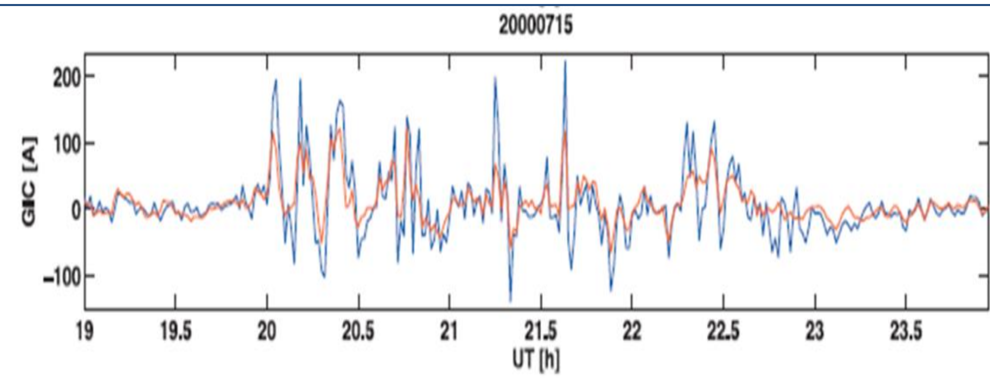

Figure 4. Measured (blue) and calculated (red) GIC at Simpevarp-2 for three events in 1998 to 2000.

Figure 32 - Plot Figure 4 from Pulkkinen, et.al.,Paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing GIC comparisons

Conclusions – Draft NERC Standards are Not Accurate and Greatly Understate Risks

As these examples illustrate the results of calculations of geo-electric fields by the NERC models and any subsequent NERC predicted GIC's appear to exhibit the same problems of significantly under predicting for intense storm disturbances. In all locations that were examined the results of the models consistently under predicted what Ohm's Law establishes as the actual geo-electric field. This is a systemic problem that is likely related to inherent modeling deficiencies, and exists in all models in the NERC GMD Task Force and likely in many other locations around the world.

This has significant implications for nearly all of the findings of the NERC GMD Task Force. These erroneous modeling approaches were utilized to examine the peak geo-electric field outputs to much higher disturbance intensities for severe storms. For example the underlying analysis performed by NERC Standard Task Force members Pulkkinen and Bernabeu[9] for the 100 Year storm peaks utilized the faulty geo-electric field calculation model to derive the peak geo-electric fields for the reference Quebec ground models. This would drastically understate the peak intensity of the storm events by the same factor of 2 to 5 ratios as noted in the prior case study analysis. Therefore the standard proposing the NERC Reference Field level of between 3 to 8 V/km would be an enormous under-estimation and result in an enormous miss-calculation of risks to society. The same modelling errors are part of all earlier Pulkkinen/Pirjola[10] derived science assessments which also examined these peaks and 100 year storm statistics. As all prior validations within this report have established, the NERC geo-electric field model under predicts geo-electric field by a factor of 2 to 5 for the most important portions of storm events. Hence these errors have been entirely baked into the NERC GMD Task Force cake and their draft standards as well. Therefore the entirety of the Draft Standard does not provide accurate assessments

[9] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

[10] Pulkkinen, A., R. Pirjola, and A. Viljanen, Statistics of extreme geomagnetically induced current events, Space Weather, 6, S07001, doi:10.1029/2008SW000388, 2008.

of the geo-electric field environments that will actually occur across the US. It has also been shown in this White Paper that undertaking a more rigorous development of validated geo-electric field standards can be done in a simple and efficient manner and that such data to drive these more rigorous findings already exists in many portions of the US. Efforts on the part of NERC's standard team and the industry to withhold this material information are counter-productive to the overarching requirements to assure public safety against severe geomagnetic storm events. Such fundamental and significant flaws in technical calculations and procedural actions should not be a part of any proposed standard and a redraft must be undertaken.

Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Mitigation

The Geomagnetic Disturbance Mitigation Drafting Team thanks all commenters who submitted comments on the standard. Project 2013-03 is developing requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in FERC Order No. 779:

- EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014. This first stage standard in the project will require applicable registered entities to develop and implement Operating Procedures.

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance events is being developed to meet the Stage 2 directives. The proposed standard will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. If the assessments identify potential impacts, the standard(s) will require the registered entity to develop corrective actions to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

TPL-007-1 was posted for a 45-day public comment period from June 13, 2014 through July 30, 2014. Stakeholders were asked to provide feedback on the standards and supporting material through a special electronic comment form. There were 74 sets of comments, including comments from over 180 individuals from approximately 130 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Summary Consideration:

As a result of comments received, the drafting team revised the standard, implementation plan, and reference material to incorporate a number of stakeholder recommendations that improve the standard. Although Section 4.12 of the NERC Standard Processes Manual indicates that the drafting team is not required to respond in writing to comments from the previous posting when it has identified the need to make significant changes to the standard, the drafting team is providing summary responses to the comments received in order to facilitate stakeholder understanding.

A summary response follows each question. Please note that because common issues were grouped together in the summaries, an individual's comment may have been addressed in the summary for a question that is different from the question in which they submitted the comment; the drafting team encourages reviewers to read all summary responses.

The drafting team made the following changes after reviewing stakeholder comments:

- Implementation Plan. The SDT changed the overall implementation schedule from 4-years to 5-years to address stakeholder concerns with coordination, model development, and resource limitations. The revised implementation plan provides six-months from the effective date of the standard for Planning Coordinators and Transmission Planners to identify responsibilities (R1) and extends other requirements in a similar manner. Additionally, the initial performance of transformer thermal impact assessments is extended to 48-calendar months from the effective date.
- Voltage Criteria. Requirement R3 (previously R4) was modified to allow responsible entities more flexibility in determining the acceptable voltage performance criteria.
- Requirement R6 (Transformer Thermal Impact Assessment). The SDT added language to clearly indicate that the requirement applies to BES power transformers meeting the applicability section 4.2 of the proposed standard. The timeline for completing thermal assessments was increased from 12-calendar months to 24-calendar months from receipt of required information from the planning entity. Also, the VRF was changed from HIGH to MEDIUM for consistency with NERC and FERC VRF Guidelines.
- Table 1 – Steady State Planning. Guidance that may have restricted manual or automatic Load shedding to meet performance requirements has been removed from footnote 3 (previously footnote 4) as suggested by stakeholders. The SDT agrees with this change as it is better aligned with the project's intent of developing standards to prevent voltage collapse, cascading and uncontrolled islanding during a 100-year benchmark event. Additionally, the SDT removed duplicative notes from Table 1.
- Attachment 1 – Benchmark GMD Event. The drafting team revised guidance for assuming an earth conductivity scaling factor when a model is not known. Attachment 1 now allows planners to select a conservative scaling factor from an adjacent physiographic region rather than use a default value. Also, an earth conductivity scaling factor was added to Table 3 for Florida, based on research by the U.S. Geological Survey (USGS).
- Requirements were reordered in response to stakeholder recommendations for a more logical sequencing. Several clarifications were made to the requirements, measures, and supporting material based on stakeholder feedback.

Several stakeholders commented on the 15 Amperes screening criterion proposed by the SDT for transformer thermal impact assessment. Stakeholders agreed with the criterion and supporting justification provided in the white paper but suggested that a separate, higher threshold should be established specifically for 3-phase power transformers. The SDT carefully considered the recommendation and the information available to support technical justification. The SDT agrees that the threshold for 3-phase 3-limb transformers is expected to be higher than the threshold for single phase units. However there is insufficient thermal measurement data of 3-phase 3-limb transformers to develop a technical justification at this time.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sandra Shaffer	PacifiCorp						X				
N/A													
2.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	5
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Wayne Sipperly	New York Power Authority	NPCC	5
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Thomas Popik	Foundation for Resilient Societies								X		

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Brian Van Gheem	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2.	John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
3.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
4.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

5.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
6.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
7.	Ginger Mercier	Prairie Power, Inc.	SERC	3
8.	William Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
9.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 3, 4, 6
10.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
11.	Matt Caves	Western Farmers Electric Cooperative	SPP	1, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Peter Heidrich	FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Giddens	Reedy Creek Improvement District	FRCC	3, 4, 5, 6
2.	Matt Pawlowski	Florida Power & Light/Nextera Energy	FRCC	1, 3, 5, 6
3.	Glenn Dooley	Duke Energy - Florida	FRCC	1, 3, 5, 6
4.	Ron Donahey	Tampa Electric Company	FRCC	1, 3, 5, 6
5.	Ken Simmons	Gainesville Regional Utilities	FRCC	1, 3, 5
6.	Ted Hobson	JEA	FRCC	1, 3, 5
7.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5, 6
8.	Keith Mutters	Orlando Utilities Commission	FRCC	1, 3, 5, 6
9.	Karen Webb	City of Tallahassee	FRCC	1, 3, 4, 5, 6
10.	Mike Antonell	Calpine Corporation	FRCC	5, 6
11.	Gary E. Willer	Indiantown Cogeneration, L.P.	FRCC	NA
12.	Doug Jensen	Northern Star Generation/Vandolah	FRCC	5
13.	Helen Nalley	Southern Power Company	FRCC	5
14.	Carol Chinn	Florida Municipal Power Agency	FRCC	3, 4, 5, 6
15.	Steve Wallace	Seminole Electric Cooperative, Inc.	FRCC	1, 3, 4, 5, 6
16.	Frank Holmes	Clay Electric Cooperative	FRCC	NA
17.	Dennis Minton	Florida Keys Electric Cooperative	FRCC	1, 3
18.	Cairo Vanegas	Fort Pierce Utilities Authority	FRCC	3, 4
19.	O.J. Garcia	City of Homestead	FRCC	3
20.	Greg Woessner	Kissimmee Utility Authority	FRCC	1, 3, 5
21.	Frank Cain	Lee County Electric Cooperative	FRCC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

22. Clay Lindstrom	City of Lake Worth	FRCC	1
23. Tim Beyrle	Utilities Commission of New Smyrna Beach	FRCC	4
24. Randy Hahn	Ocala Utility Services	FRCC	3
25. Robert Doty	City of Vero Beach	FRCC	1
26. Israel Melendez	Constellation Energy	FRCC	5
27. Paterick McGovern	Georgia Transmission Corp.	FRCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Randi Heise		MRO	NA
2. Mike Garton		NPCC	5
3. Louis Slade		RFC	5, 6
4. Larry Nash		SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirsEnergy Corp	RFC	1
2. Cindy Stewart	FIrstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6
6. Richard Hoag	FirstEnergy Corp	RFC	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Joe Wilson	Tacoma Public Utilities	X		X	X	X	X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	David Greene	SERC Planning Standards Subcommittee										

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Kelley	PowerSouth		
2. Shih-Min Hsu	Southern Company Services		
3. Phil Kleckley	SCE&G		

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
4. James Manning	NCEMC		
5. David Greene	SERC		

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Paul Haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Pawel Krupa	Seattle City Light		1
2. Dana Wheelock	Seattle City Light		3
3. Hao Li	Seattle City Light		4
4. Mike Haynes	Seattle City Light		5
5. Dennis Sismaet	Seattle City Light		6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Tom McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3
3. John Babik		FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Erika Doot	Bureau of Reclamation	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. Richard Jackson	Bureau of Reclamation	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hills		RFC	1
2. Lee Schuster		FRCC	3
3. Dale Goodwine		SERC	5
4. Greg Cecil		FRCC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Marjorie Parsons		SERC	3
2. Ian Grant		SERC	6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

3.	DeWayne Scott	SERC	1

				1	2	3	4	5	6	7	8	9	10
18.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Coop	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
19.	Group	Wayne Johnson	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	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
20.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

				1	2	3	4	5	6	7	8	9	10
21.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Dave Szulczewski	DE-EE Relay Eng		

				1	2	3	4	5	6	7	8	9	10
22.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shannon V. Mickens		SPP	2
2.	Matt Boredelon		SPP	1, 3, 5, 6
3.	Neal Faltys		SPP	1, 3, 5
4.	Michael Herzog		SPP	1, 3, 5
5.	Mahmood Safi		SPP	1, 3, 5
6.	Jon Shipman		SPP	1, 3, 5
7.	James Simms		SPP	1, 3, 5, 6
8.	Bo Jones		SPP	1, 3, 5, 6
9.	Mo Awad		SPP	1, 3, 5, 6
10.	Derek Brown		SPP	1, 3, 5, 6
11.	Kevin Giles		SPP	1, 3, 5, 6
12.	Jonathan Hayes		SPP	2
13.	Ron Losh		SPP	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Robert Rhodes		SPP 2										
15. James Nail		SPP 3										
16. Don Schmit		SPP 1, 3, 5										
23. Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								
Additional Member	**Additional Organization**	**Region / Segment Selection**										
1. Cheryl Moseley	ERCOT	ERCOT 2										
2. Ali Miremadi	CAISO	WECC 2										
3. Ben Li	IESO	NPCC 2										
4. Margoth Caley	ISO-NE	NPCC 2										
5. Terry Bilke	MSIO	MRO 2										
6. Stephanie Monzon	PJM	RFC 2										
7. Charles Yeung	SPP	SPP 2										
24. Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
Additional Member	**Additional Organization**	**Region / Segment Selection**										
1. Berhanu Tesema	Transmission Planning	WECC 1										
2. Richard Becker	Substation Engineering	WECC 1										
3. Don Watkins	System Operations	WECC 1										
4. Dan Goodrich	Technical Operations	WECC 1										
5. Ran Xu	Technical Operations	WECC 1										
25. Individual	Frederick R Plett	Massachusetts Attorney General								X		
26. Individual	John Bee on behalf of Exelon and its affiliates	Exelon	X		X		X					
27. Individual	Terry Volkmann	Volkmann Consulting, Inc	X							X		
28. Individual	shirin.friedlander@ladwp.com	ladwp	X		X		X	X				
29. Individual	Neel Savani	George mason University/ naval Research lab									X	
30. Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X							
31. Individual	Ayesha Sabouba	Hydro One			X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
33.	Individual	Paul Rocha	CenterPoint Energy	X									
34.	Individual	Eric Bakie	Idaho Power	X									
35.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
36.	Individual	Anthony Jablonski	ReliabilityFirst										X
37.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
38.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
39.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
40.	Individual	Bill Temple	Northeast Utilities	X									
41.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
42.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X				X	X				
43.	Individual	Johannes Raith	Siemens AG Austria - Transformers Weiz										
44.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
45.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
46.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
47.	Individual	Rick Terrill	Luminant Generation Company LLC					X					
48.	Individual	Glenn Pressler	CPS Energy	X		X		X					
49.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
50.	Individual	Ayesha Sabouba	Hydro One			X							
51.	Individual	Frederick	Emprimus										
52.	Individual	Brenda Hampton	Luminant Energy Company, LLC						X				
53.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
54.	Individual	Michelle D'Antuono	Ingleside Cogeneration, LP					X					
55.	Individual	Oliver Burke	Entergy Services, Inc.	X									
56.	Individual	David Thorne	Pepco Holdings Inc	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
57.	Individual	Karin Schweitzer	Texas Reliability Entity										X
58.	Individual	David Jendras	Ameren	X		X		X	X				
59.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
60.	Individual	Rich Salgo	NV Energy					X					
61.	Individual	George H. Baker	James Madison University								X		
62.	Individual	Dan Inman	Minnkota Power Corporative	X									
63.	Individual	Mark Wilson	Independent Electricity System Operator		X								
64.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
65.	Individual	Gul Khan	Oncor Electric LLC	X									
66.	Individual	Richard Vine	California ISO		X								
67.	Individual	Teresa Czyz	Georgia Transmission Corporation	X		X							
68.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X							
69.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
70.	Individual	Russell Noble	Public Utiltiy District No. 1 of Cowlitz County, WA			X	X	X					
71.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
72.	Individual	Eric Olson	Transmission Agency of Northern California	X									
73.	Individual	Bill Fowler	City of Tallahassee			X							
74.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
JEA	Agree	FRCC
Tennessee Valley Authority	Agree	Planning Standards Subcommittee
George mason University/ naval Research lab	Agree	small comment: reference 6 and 21 are identical within Benchmark_GMD_Event_June12.pdf
Kansas City Power & Light	Agree	SPP - Robert Rhodes
Consolidated Edison Co. of NY, Inc.	Agree	NPCC (Northeast Power Coordinating Council)
NV Energy	Agree	PacifiCorp
Occidental Chemical Corporation	Agree	Ingleside Cogeneration LP
California ISO	Agree	ISO/RTO Council Standards Review Committee
Transmission Agency of Northern California	Agree	Sacramento Municipal Utility District
City of Tallahassee	Agree	FRCC Regional Entity Committee and Compliance Forum

Organization	Agree	Supporting Comments of “Entity Name”
Colorado Springs Utilities		Southwest Power Pool (SPP)
ladwp		o The Standard Development Team (SDT) should make it clear that if a responsible entity finds that the GMD Vulnerability Assessment meets the performance requirements of Table 1, it will not have to undertake any Operating Procedures and Mitigating Measures. o LADWP recommends that the Regional Entities review NERC recommendations for modeling, simulation and other related matters, and provide additional guidance to Responsible Entities on modeling, simulation, and potential of GIC in their respective areas, taking into account geography, geology and system topology. Perhaps a regional-wide effort is in order here.
Minnkota Power Corporative		Minnkota supports the NSRF comments

1. **Organization of the Requirements in TPL-007-1. The SDT has reorganized the standard in response to stakeholder comments. The revised draft is more closely aligned with the steps in the GMD Vulnerability Assessment process. The SDT has also created a flow chart of the overall assessment process. Do these steps address the concerns about the organization of TPL-007-1? If you do not agree or want to provide other recommendations on the organization of the standard please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on the organization of TPL-007. All comments have been reviewed and changes that the SDT supported have been incorporated into the revised version of TPL-007-1 Stakeholders generally supported the organization of the proposed standard. However, the SDT agreed with commenters that suggested reordering the requirement for performing the GMD Vulnerability Assessment and the requirement for establishing System steady state voltage criteria. A summary of comments and the SDT's response is provided below. Some commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here:

- **Respective roles of the TP and PC. Comments suggested that the respective roles be clarified with specific responsibilities assigned for each registered entity to eliminate duplication and confusion.** For the standard to be applicable in all regions, the SDT intends to maintain flexibility as provided in Requirement R1 which specifies each PC, in conjunction with its TPs, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's area. This approach is the same as the one taken in other planning standards.
- **Data requirements. Commenters stated that the standard needed a requirement for entities to provide data to the PC and TP for development of the required models, including specific time requirements such as 'within 90 days'. Some commenters recommended assigning responsibility for maintaining system models to the ERO or its designee.** The SDT believes that requirements for providing modeling data to PCs and TPs are addressed in MOD-032-1 and that an additional requirement in TPL-007 would be redundant. MOD-032 establishes consistent modeling data requirements and reporting procedures for the planning horizon and includes PC, TP, GO, and TO among the applicable entities. MOD-032 also addresses requirements for establishing reporting timelines and for making models available to the ERO or its designee.
- **BES Applicability. Commenters expressed concerns with the draft standard and the revised BES definition. Commenters recommended modifications to the applicability section or to requirements to restrict applicability to BES equipment. A commenter recommended removing the 200 kV threshold in applicability section 4.2 to be consistent with the BES definition.** The SDT acknowledges that parts of the proposed standard apply to non-BES facilities. This is necessary to accurately model GIC since grounded 200kV and higher facilities can impact the GIC calculations. Therefore, Requirement R2 (Maintain System Models) could include non-BES elements that the planner determines are necessary for performing the studies required to complete its GMD Vulnerability Assessment. This applicability is consistent with Order No. 779, which references the "Bulk-

Power System." On the other hand, Requirement R6 applies only to applicable BES power transformers and the SDT has revised the requirement for clarity. Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected transmission system. The 200 kV threshold included in applicability section 4.2.1 is based on analysis indicating that the GIC impact on the network from facilities less than 200kV is minimal due to increased impedance. This analysis is included in the white paper that was developed during stage 1 of Project 2013-03 and available on the project page: http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/ApplicableNetwork_clean.pdf.

- **Reorder Requirements. Commenters suggested that the order would be more logical if the requirement for establishing system steady state voltage criteria preceded the requirement for preforming a GMD Vulnerability Assessment.** The drafting team agrees and has reordered these requirements in the draft standard.
- **Clarification of acceptable evidence demonstrating that agreement has been reached on individual and joint responsibilities (R1/M1).** The SDT revised measure M1 to include the following additional evidence, as recommended: copies of procedures or protocols in effect between entities or between departments of a vertically integrated system.
- **Additional details in the requirements or application guidelines section. Commenters asked for clarification on accounting for storm orientation in GIC studies and recommended that these details be included in the application guideline section. A commenter suggested wording changes to the flow chart in the application guidelines section. Some commenters also stated that the requirements lacked sufficient details of the studies and analysis required.** The SDT understands that studies required for GMD Vulnerability Assessments are new to many in the industry. However, technical guidance provided in the GMD Task Force guidelines and the SDT white papers is expected to enable responsible entities to comply with the standard. Steady state analysis and storm orientation are discussed in Section 2.1.2 of the GMD Planning Guide. A load flow that accounts for GIC flows on the system is performed for each storm orientation. The SDT considered the suggested wording change to the GMD Vulnerability Assessment flow chart but did not believe that the change improved clarity.

Organization	Yes or No	Question 1 Comment
PacifiCorp	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.

Organization	Yes or No	Question 1 Comment
Foundation for Resilient Societies	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.
ACES Standards Collaborators	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.
SERC Planning Standards Subcommittee	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

Organization	Yes or No	Question 1 Comment
		Benchmark GMD event?If so, please add these details to the reference material and to the Application Guideline for R3.
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.
ISO/RTO Council Standards Review Committee	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

Organization	Yes or No	Question 1 Comment
		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.
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.
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)”.
James Madison University	No	
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

Organization	Yes or No	Question 1 Comment
		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.
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.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Northeast Power Coordinating Council	Yes	
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
Colorado Springs Utilities	Yes	No Comments
Bureau of Reclamation	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 1 Comment
MRO NERC Standards Review Forum	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.
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	Yes	
PPL NERC Registered Affiliates	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.
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
Massachusetts Attorney General	Yes	
Exelon	Yes	

Organization	Yes or No	Question 1 Comment
Volkmann Consulting, Inc	Yes	
ladwp	Yes	
Hydro One	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Idaho Power	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	The revised organization is an improvement - no concerns.
Nebraska Public Power District	Yes	
LCRA Transmission Services Corporation	Yes	
American Electric Power	Yes	
Luminant Generation Company LLC	Yes	
Hydro One	Yes	
Emprimus	Yes	
Luminant Energy Company, LLC	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 1 Comment
Entergy Services, Inc.	Yes	
Pepco Holdings Inc	Yes	
Texas Reliability Entity	Yes	
Liberty Electric Power LLC	Yes	
Minnkota Power Corporative	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
MidAmerican Energy	Yes	
DTE Electric		No Comment
Public Utiltiy District No. 1 of Cowlitz County, WA		Cowlitz defers to the Planning Coordinators and Transmission Planners.

2. **Benchmark GMD Event. The SDT has provided additional guidance in TPL-007-1 Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event). Changes include how a planning entity with a large geographic area can handle scaling factors in the planning area, and specific guidance on earth conductivity scaling when the planning entity does not have a ground conductivity model. During informal comments, many commenters indicated that they agreed with the proposed benchmark GMD event and no substantive changes have been made. Do you agree that the guidance in TPL-007-1 Attachment 1 provides the required details for applying the proposed benchmark GMD event? If you do not agree or have additional new comments on the proposed benchmark GMD event, please provide specific technically justified suggestions for the SDT to consider.**

Summary Consideration: The drafting team thanks all who commented on the benchmark GMD event. All comments have been reviewed and changes that the SDT supported have been incorporated into the revised version of TPL-007-1 and supporting white papers. A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections.

- **Scaling factors for large geographic areas. Several commenters did not agree with the SDT's approach or requested additional technical information on applying scaling factors to planning areas that span more than one latitude or geophysical area. A commenter asked for information on the availability of tools that were capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field as stated in Attachment 1.** The SDT has clarified TPL-007-1 Attachment 1. The statement now reads: "For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field." A similar statement in Attachment 1 provides guidance to address the geomagnetic latitude scaling factor alpha in a large area. Commercial tools can assign different geoelectric fields (V/km) to different parts of the system on the basis of different scaling factors. This is a reasonable approximation for the use of a non-uniform geoelectric field. The statement "Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field." is intended to permit utilities with more sophisticated tools to use them, and to allow for application of future developments in commercial GMD analysis software.
- **Effective GIC. A Commenter stated that Effective GIC should be explicitly defined.** Effective GIC is defined in the white papers and in the NERC GMDTF Application guide.
- **Determining geomagnetic latitude and the geomagnetic latitude scaling factor. A commenter stated that Figure 1 in Attachment 1 lacks precision, and that the equation for the scaling factor alpha in attachment 1 provides a more precise value than Table 2.** The figure is intended for illustration purposes only. The SDT agrees that it is better to either use-geophysical software or calculators provided in one of a number of web sites such as: http://omniweb.gsfc.nasa.gov/vitmo/cgm_vitmo.html

- **Earth models. A commenter stated that the standard does not specify criteria for a technically-justified earth model to be used as a substitute for attachment 1 Table 3.** The SDT modified Attachment 1 to more clearly indicate that a responsible entity may use a specific earth model(s) with with documented justification.
- **Technical justification for the geomagnetic waveshape. A commenter stated that the justification for using the March 1989 event did not conclude that this was the worst case waveshape; and that they disagreed with assumptions of transformer thermal effects without testing of multiple designs.** The SDT has provided justification for using this waveshape in thermal assessments. The white paper shows that it is conservative from thermal assessment point of view when compared to other major GMD events. The SDT's assumptions about transformer heating are consistent with published technical literature.
- **Earth conductivity scaling factor validity. A commenter stated that the scaling factors did not account for proximity to salt water bodies. Another commenter stated that GIC data measured in two stations located in coastal areas do not match calculations made with USGS earth models.** The geoelectric field scaling factors in Attachment 1 do not include costal effects because they reflect average earth models available from USGS and NRCan. The standard does not preclude an entity from using more detailed earth models and including geoelectric field enhancements or coastal effects at the edge of salt water bodies.
- **Geomagnetic latitude scaling validity. Commenters questioned the technical basis for alpha scaling factors.** As indicated in the Benchmark GMD Event white paper, the alpha scaling factors are based on global geomagnetic field observations of 12 major or extreme geomagnetic storms since the late 1980s (Thomson et al., 2011; Pulkkinen et al., 2012; Ngwira et al., 2013). For all observed storm events, the maximum expansion of the auroral region was identified and the corresponding time derivatives of the ground magnetic field (dB/dt) or geoelectric field magnitudes were computed. The approximate factor of 10 fall of the dB/dt and associated geoelectric field magnitudes between geomagnetic latitudes from 60 degrees to 40 degrees represent the general trend that was observed for all studied storm events at the time of the maximum expansion of the auroral region. In summary, the selected geomagnetic latitude scaling is based on global geomagnetic field observations of major or extreme storm events and represents approximate field scaling at the time of the maximum expansion of the auroral region.
- **Validity of the method used to generate geoelectric field scaling factors. A commenter stated that the plane wave method used to calculate geoelectric fields from geomagnetic field data produces incorrect results and it systematically produces low geoelectric field values.** The plane wave method that was utilized in the generation of the NERC GMD benchmark event has been applied extensively in GIC studies over the past several decades. The method has been shown in numerous studies to accurately map the observed ground magnetic field to the geoelectric field and observed GIC (e.g., Trichtchenko et al., 2004; Viljanen et al., 2004; Viljanen et al., 2006; Pulkkinen et al., 2007; Wik et al., 2008). Further, although the plane wave method assumes a one-dimensional (1D) ground conductivity structure, the method has been shown to be applicable even in highly non-1D situations if an effective 1D ground conductivity is used (Thomson et al., 2005; Ngwira et al., 2008; Pulkkinen et al. 2010). **The same commenter showed an example comparing the geoelectric field calculated using a USGS model and the geoelectric field**

estimated from GIC measurements and stated that calculations using USGS models will consistently result in lower peak maxima. Comparisons with measured data are valuable tools to validate and improve earth models. There are efforts in the industry to validate and adjust average earth models on the basis of GIC and magnetometer measurements. This type of validation has to be done carefully in order to avoid numerical issues caused by using data with different sampling rates and thus mask differences due to inaccuracies in the earth model to be validated. The example presented by the commenter used downsampled 1 minute geomagnetic field data from the OTT geomagnetic observatory on May 4 1998 to calculate the geoelectric field from the "NERC" model. When the same calculations are carried out using 5 second geomagnetic field data from the same observatory, calculated geoelectric field peak maxima increase by a factor of 1.5 to 1.9. The use of 1 minute magnetometer data will always result in lower calculated peak maxima.

- **Technical justification and methods for determining the benchmark GMD event. Some commenter did not agree with the application of magnetometer data from Europe to determining the benchmark, or with the spatial averaging technique described in Appendix I of the Benchmark GMD Event white paper. A commenter did not support a 100-year benchmark or including specific engineering margin in the benchmark, while others commented that the margin was too high or too low. Commenters argued for basing the benchmark event on other information such as EPRI SUNBURST data, or on an entity's own local magnetometer data.** The SDT developed a consistent benchmark for application across the Bulk-Power System as outlined in the Standard Authorization Request and Order No. 779. Allowing entities to establish their own benchmark will not achieve the objectives outlined in the SAR and FERC Order. The SDT believes a 100-year benchmark is appropriate due to the broad geographical scale inherent in a major GMD event. A data set of high resolution modern magnetometer observations that has been used extensively in space weather research was used in the benchmark analysis. The SDT maintains that spatial averaging is supported by the magnetometer data and justified for determining the wide-area impacts on the power system. The North American magnetometer network is too sparse to be used as the basis of spatial averaging. Nevertheless, the statistical storm peaks recorded in North America are consistent with those recorded in Europe. The spatially-averaged uniform geoelectric field assumption takes into consideration wide-area geoelectric field values. Data used to determine the benchmark thresholds are spatially averaged, not time averaged. Data in Figure I-2 of the benchmark definition white paper reflect only event peak event values. It is not based on the assumption that 3 V/km represents some kind of sustained average value while 8 V/km represents a 10s duration peak.
- **Multiple benchmarks and alternate approaches. A commenter recommended a 3 V/km benchmark for performance requirements and an 8 V/km benchmark for studies only. A commenter recommended an alternate approach requiring GIC monitoring and hot-spot monitoring to calibrate models.** The SDT agrees that earth models need to be validated and possibly modified on the basis of recorded GMD events. There are a number of initiatives in place to do precisely that. There are however, some difficulties in the approach proposed: Hot spot measurements can only be carried out when the unit is instrumented in the factory and placed in service with appropriate data acquisition provisions. Recorded GIC can only be

validated against an earth model when geomagnetic field measurements are made at the same time. Efforts are underway to increase the number of magnetic field measurements in North America for this purpose. Initiatives to validate earth and transformer thermal models will take years.

- **Margin estimation. A commenter indicated that adding a margin to extreme value analysis results to arrive at 8 V/km is unrealistically conservative.** The SDT has used extreme value analysis to support the extrapolation to a 1 in 100 year frequency in Figure I-2 of the GMD benchmark event white paper. Stating that an engineering margin was added to the results of extreme value analysis is inaccurate and the text in white paper has been modified accordingly.
- **Concerns with specific ground models referenced in TPL-007 Attachment 1. Commenters stated that the standard should not be applicable to entities in Florida without further justification of the proposed scaling factor. Commenters questioned validity of ground models in some areas.** NERC has highlighted the need for a Florida earth model with USGS and other research organizations and several efforts are underway that are expected to fill this gap within the implementation timeline for TPL-007. USGS has responded by producing a preliminary earth model for Florida (CP3), and the corresponding scaling factor has been added to Table II-2 of the GMD benchmark white paper and to Table 3 of Attachment 1. The SDT wants to reiterate that the scaling factors represent the current knowledge on the basis of the average earth models available from USGS and NRCan. The standard allows the use of technically justified earth models. Technical justification could take the form of updates from USGS and NRCan, as well as adjustments on the basis of concurrent GIC and geomagnetic field measurements.
- **Peer Review. A commenter recommended NERC initiate a peer review to satisfy OMB guidance. A commenter questioned the adequacy of review by space weather experts.** Although this OMB bulletin does not apply to NERC, NERC uses peer-reviewed research to the maximum extent possible.
- **Implementation with a technical evaluation. A commenter asked about pilot evaluations of the GMD assessment process and recommended a pilot project.** A number of GMD studies have been carried out in US and Canadian utilities using the evaluation methods required in the standard including a number of utilities in the NERC GMD Task Force. The Standard is responsive to the FERC order and is based on technical work of the GMD TF. The proposed phased approach for implementation provides similar benefits to a formal pilot project.

Organization	Yes or No	Question 2 Comment
PacifiCorp	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)

Organization	Yes or No	Question 2 Comment
		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 Î± 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
Associated Electric Cooperative, Inc. - JRO00088	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.
Northeast Power Coordinating Council	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

Organization	Yes or No	Question 2 Comment
		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.htmlThe 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-

Organization	Yes or No	Question 2 Comment
		area impact, as opposed to 20 V/km estimate when only storm peaks were considered in the 2012 NERC GMD interim report.
Foundation for Resilient Societies	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 Description1. 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

Organization	Yes or No	Question 2 Comment
		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.
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	No	Scaling Factor for FRCC RegionThe 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 Â§ 706(2)(A). Therefore, the FRCC RECCF requests that the SDT delay any further

Organization	Yes or No	Question 2 Comment
		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,

Organization	Yes or No	Question 2 Comment
		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.
Colorado Springs Utilities	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.
MRO NERC Standards Review Forum	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 Î² 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

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		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.
SPP Standards Review Group	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 Î² 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.
Volkmann Consulting, Inc	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.
Manitoba Hydro	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

Organization	Yes or No	Question 2 Comment
		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

Organization	Yes or No	Question 2 Comment
		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

Organization	Yes or No	Question 2 Comment
		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.

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Hydro-Quebec TransEnergie	No	The benchmark GMD Event is a new approach that needs to be well mastered before being adopted. Hydro-QuÃ©bec TransÃ‰nergie is concerned with the Benchmark GMD Event proposed in Attachment 1 and the high value of the geoelectric field of 8 V/km: o 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. o 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. o The B field should not be considered uniform, especially for a very wide area. o 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.
Nebraska Public Power District	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

Organization	Yes or No	Question 2 Comment
		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.
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 Î² should be used in scaling the geoelectric field.' For example, using the largest value for Î² 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 Î² may result in adjacent planning areas in the same region using different values for Î². To account for this issue, LES suggests modifying the standard to allow for the use of engineering judgment when determining the value for Î².
MidAmerican Energy	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

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		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.
Emprimus	No	Response to NERC Draft Benchmark GMD Event Description - Under FERC Order 779 By Dr. Frederick Faxvog, Gale Nordling, Greg Fuchs, David Jackson, Wallace JensenExecutive SummaryFERC, 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

Organization	Yes or No	Question 2 Comment
		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

Organization	Yes or No	Question 2 Comment
		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 DisturbancesThe 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 ApproachThe 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 ScalingThe 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

Organization	Yes or No	Question 2 Comment
		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 StormThe 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 OptionThe 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 HarmonicsThe 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

Organization	Yes or No	Question 2 Comment
		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 AgainThe 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 TeamThe 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 StandardIn 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

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		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 ExpensiveIt 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.
Ameren	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

Organization	Yes or No	Question 2 Comment
		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.
James Madison University	No	I have grave concerns about the methods used to calculation of geoelectric fields. See comments under question 7.
Minnkota Power Corporative	No	See NSRF Comments
Independent Electricity System Operator	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.
Oncor Electric LLC	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 Î² should be used in scaling the geoelectric field.” We recommend that engineering analysis be used for

Organization	Yes or No	Question 2 Comment
		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.
Tri-State Generation and Transmission Association, Inc.	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 Î² 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.
ACES Standards Collaborators	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.
Arizona Public Service Company	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
SERC Planning Standards Subcommittee	Yes	
Bureau of Reclamation	Yes	
Duke Energy	Yes	
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	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Massachusetts Attorney General	Yes	

Organization	Yes or No	Question 2 Comment
Exelon	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.
ladwp	Yes	
Hydro One	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.

Organization	Yes or No	Question 2 Comment
American Transmission Company, LLC	Yes	
CenterPoint Energy	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.
Idaho Power	Yes	
Xcel Energy	Yes	
Northeast Utilities	Yes	
LCRA Transmission Services Corporation	Yes	
American Electric Power	Yes	
Hydro One	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

Organization	Yes or No	Question 2 Comment
		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.
Public Service Enterprise Group	Yes	
Ingleside Cogeneration, LP	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.
Entergy Services, Inc.	Yes	
Pepco Holdings Inc	Yes	

Organization	Yes or No	Question 2 Comment
Texas Reliability Entity	Yes	
Georgia Transmission Corporation	Yes	
DTE Electric		No Comment
Public Utiltiy District No. 1 of Cowlitz County, WA		Cowlitz defers to the Planning Coordinators and Transmission Planners.

3. **Transformer Thermal Impact Assessment. The SDT revised the requirement for conducting transformer thermal impact assessments. In the revised draft TPL-007-1, only those applicable transformers have calculated GIC flow of 15 Amperes or greater per phase of effective geomagnetically-induced current (GIC) are required to conduct a transformer thermal impact assessment. A review of available transformer thermal models supports this as a conservative screening criteria. Do you agree with the proposed 15 Amperes threshold? If you do not agree or have recommended changes to the transformer thermal impact assessment requirement please provide your suggestion and technical justification, if applicable.**

Summary Consideration: The drafting team thanks all who commented on the transformer thermal impact assessment. All comments have been reviewed and the revised version of TPL-007-1 and supporting white papers include changes.

A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections:

- **Screening criteria. Commenters stated that 15A threshold was overly conservative, particularly for some types of transformers. Commenters proposed that a percent-loading threshold be included so that light-loaded transformers were excluded from thermal assessment, or that a higher GIC screening threshold be established for transformers that are operated below nominal power. A commenter recommended that a thermal impact assessment not be required for any transformer with a GIC design specification in excess of the calculated GIC in Requirement R5. A commenter noted that the transformer thermal screening criterion whitepaper cited only equipment rated 400 MVA or less and asked if the criterion was also valid for larger equipment.** The SDT agrees that the threshold for 3-phase 3-limb transformers is expected to be higher than the threshold for single phase units. However there is insufficient thermal measurement data of 3-phase 3-limb transformers to develop a technical justification at this time. The SDT also agrees that a design specification is a valid criteria for determining whether a transformer thermal impact assessment is required and has added this criteria to the application guidelines section. The drafting team agrees that loading and ambient temperatures have a direct bearing on hot spot thermal limits. However, different transformer types have different temperature/loading performance and cooling modes. From a planning perspective it is not possible to anticipate planned or unplanned outages and system configuration. Therefore, a general threshold on the basis of loading temperatures is not prudent. This does not prevent using a technically supportable loading-based assessment on a case-by-case basis as indicated in the white paper. Also it is generally not possible to anticipate a % loading that would apply to the exact system configuration in view of planned and unplanned outages and contingencies. The temperature rise due to hot spot heating thresholds due to half-cycle saturation do not depend on the transformer MVA rating.
- **Technical basis for thermal assessments. A commenter disagreed with the white paper because the thermal heating models used as examples were not compared against experimental data. A commenter did not agree that thermal time constants were on the order of minutes to tens of minutes as described in the white paper.** The white paper now includes an example of

a comparison with measured results. Winding and metallic hot spot time constants to a GIC step mentioned in the white paper are based on published measurements and manufacturer-calculated and measured hot spot temperature rises (e.g., Fingrid transformer) and are not consistent with temperature time constants of 20 to 60 s.

- **Temperature limits. A commenter believes using IEEE Std. C57.91 emergency loading limit of 120 C is overly conservative and suggested 130 C or 140 C. The commenter also stated that the thermal impact assessment white paper did not take transformer defects into account.** According to Std. IEEE 57.91, a hot metallic part hot spot during the emergency overloading time frame will not cause gassing in a healthy unit. The SDT believes this is the most appropriate criteria currently available. To account for the condition of a particular transformer, an owner can de-rate a transformer thermal limit. This is discussed in the white paper.
- **Transformer thermal impact assessment approach. A commenter did not agree with the overall approach stating it did not consider several non-linear phenomena relevant to transformer heating due to GIC. A commenter asked for clarification on the duration of the GIC time-series, while another commenter proposed an alternate approach based on a fixed-time pulse of GIC determined based on transformer rating.** The sample method to calculate the thermal response is peer-reviewed and the white paper shows that it reproduces the Fingrid measurements. The white paper has been modified to include these results. This method uses a linearized approximation of the asymptotic response to different GIC steps. All nonlinear effects are taken into consideration. This is simply a method to model a known transformer thermal step response in order to calculate incremental hot spot temperatures as a function of time caused by an arbitrary GIC(t). The transformer thermal step response needs to be known or assumed from measurements or calculations. When the step responses are known only for low values of GIC, the linear extrapolation of asymptotic response is known to be conservative, on the basis of measurement data. However, in the absence of information on a specific transformer, it is a simple way to obtain conservative values. The standard does not place any restrictions on the transformer thermal response used in the assessment, so long as it is technically justifiable. For instance, technical justification would be a manufacturer warranting a specific or general thermal response.
- **Scope of transformer assessments. A commenter stated that the standard should also include assessments for shock or vibration impacts.** Vibration is not considered in the standard because available information is sparse, mostly anecdotal and not likely to have a wide area impact on the network.
- **A commenter disagreed with the requirement in R2 part 2.1 to study off-peak conditions.** Minimum loading should be examined because the generation pattern and thus the distribution and availability of reactive power resources are completely different than on-peak conditions.
- **Effective GIC. A commenter did not agree with the calculation for effective GIC.** The equivalent GIC formula in an autotransformer is based on ampere-turns, not resistance. Ampere-turns determine the degree to which the core is saturated, which in turn, determines the eddy currents and harmonics that cause hot spot heating. The GIC proportion in HV and LV windings depends on factors such as circuits connected to the transformer buses (length and resistance), station grounding

resistance and number of transformers connected to the bus. The impact of winding resistance on the level of saturation of the transformer has only a minor effect on GIC distribution in the windings. The effective current used to calculate GIC(t) is a simple and direct result of the dc simulation of the network.

- **Cost and availability of manufacturer GIC capability curves or models. Commenters are concerned that models will not be available from manufacturers and that default models are unavailable. A commenter recommended that the standard include allowances for application of 'sound engineering judgment'.** The SDT agrees that industry-vetted default thermal models would be beneficial to the industry. It is in the scope of work for the NERC GMDTF is evaluate available models and provide guidance. This would be a better forum for discussion and vetting. In response to stakeholder concerns, the revised implementation plan provides four years before the thermal assessment requirement become effective.
- **Tertiary windings. A commenter indicated that tertiary winding heating is a major problem because tertiary windings have a lower MVA rating than main windings (some below 5%).** Heating due to harmonics and stray flux in the tertiary winding does take place. The thermal impact assessment is intended to examine metallic part and winding hot spot heating. The requirement is not specific to a particular winding.
- **Entity obligations for R6 part 6.3 Suggested Actions. A commenter stated that it was unclear how suggested mitigation actions are implemented.** Part 6.3 specifies that the owner must communicate actions to mitigate the impact of GICs on the applicable power transformer and provide supporting analysis to the planning entity conducting the GMD Vulnerability Assessment. This provides the necessary feedback for the planner to account for potential impact in the assessment. The SDT believes this is an effective approach consistent with planning standards.
- **Thermal assessment tools. Commenters stated that software tools were needed for thermal assessment. A commenter supported the approach but highlighted the importance of transformer design-specific models.** The SDT agrees that the precise thermal response is design-dependent and anticipates that this standard will influence transformer manufacturers to produce families of technically-justified conservative default for the industry to use. Special software is only one of methods that can be used to carry out a thermal assessment. For example, an entity can use manufacturer-supplied capability curves. Specifications for new transformers can require OEM to perform the thermal assessment and provide the necessary GIC rating curves to the customer. The NERC website provides one software implementation of a peer-reviewed method to estimate hot spot temperature rise when a transformer thermal step response to GIC is known. This implementation can be used to carry out thermal assessments. http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Planning-Tools.aspx

Organization	Yes or No	Question 3 Comment
PacifiCorp	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.
Northeast Power Coordinating Council	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 15A3-phase core-type and other 50AA 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

Organization	Yes or No	Question 3 Comment
		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.
Foundation for Resilient Societies	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: o Hot spot heating of transformer windings due to stray flux; o Hot spot heating of non-current carrying transformer metallic members due to stray flux; o Harmonics; o Increase in reactive power absorption; and o 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 noiseare 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

Organization	Yes or No	Question 3 Comment
		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.
PPL NERC Registered Affiliates	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.
DTE Electric	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.
Manitoba Hydro	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

Organization	Yes or No	Question 3 Comment
		manufacturer confirmed withstand levels). Referring to the “Transformer Thermal Impact Assessment White Paper”: o 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. o 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. o 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

Organization	Yes or No	Question 3 Comment
		dc amps? If this curve is for a 10 to 15 kA transformer that is a poor example to give. o 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. o 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

Organization	Yes or No	Question 3 Comment
		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?
Hydro-Quebec TransEnergie	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.
Emprimus	No	The GMD standard does not adequately consider transformers with tertiary windings which makes these transformers more vulnerable to GIC currents and subsequent heating.

Organization	Yes or No	Question 3 Comment
Ameren	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?
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ACES Standards Collaborators	Yes	
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
Colorado Springs Utilities	Yes	No Comment
Bureau of Reclamation	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	Yes	
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	Yes	
SPP Standards Review Group	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Massachusetts Attorney General	Yes	
Exelon	Yes	
Volkmann Consulting, Inc	Yes	
ladwp	Yes	

Organization	Yes or No	Question 3 Comment
Hydro One	Yes	It is difficult to come up with a different threshold until entities have more experience.
American Transmission Company, LLC	Yes	
CenterPoint Energy	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

Organization	Yes or No	Question 3 Comment
		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

Organization	Yes or No	Question 3 Comment
		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.
Idaho Power	Yes	
Xcel Energy	Yes	
Nebraska Public Power District	Yes	
Northeast Utilities	Yes	
LCRA Transmission Services Corporation	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	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.
Hydro One	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-

Organization	Yes or No	Question 3 Comment
		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.
Public Service Enterprise Group	Yes	
Ingleside Cogeneration, LP	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.
Entergy Services, Inc.	Yes	
Pepco Holdings Inc	Yes	
Texas Reliability Entity	Yes	
James Madison University	Yes	

Organization	Yes or No	Question 3 Comment
Minnkota Power Corporative	Yes	
Independent Electricity System Operator	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.
Oncor Electric LLC	Yes	
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	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.
Public Utiltiy District No. 1 of Cowlitz County, WA	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.
MidAmerican Energy	Yes	
SERC Planning Standards Subcommittee		no comment
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

Organization	Yes or No	Question 3 Comment
		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)
Luminant Generation Company LLC		We do not have enough information to effectively evaluate this methodology.
Luminant Energy Company, LLC		We do not have enough information to effectively evaluate this methodology.

4. **Implementation. The SDT revised the proposed Implementation Plan based on stakeholder comments. The changes provide additional time for completing transformer thermal impact assessments. An overall timeline of four-years from the standard's effective date until completion of all steps in the GMD Vulnerability Assessment process including development of a Corrective Action Plan, if required, has been maintained. Do you support the approach taken by the SDT in the proposed Implementation Plan? If you do not agree with the proposed Implementation Plan, please provide your recommended changes and justification.**

Summary Consideration: The drafting team thanks all who commented on the Implementation Plan. All comments have been reviewed and the revised Implementation Plan is extended from 48 months to 60 months with the following specific changes:

- **Requirement R1. Some commenters indicated that 60 days was not enough time to meet with the Transmission entities and agree on an assigned set of responsibilities.** The SDT agrees with the comments and has changed proposed effective date to 6 months (from 60 days).
- **Requirement R2. Some commenters indicated that not enough time was provided to develop the models necessary to undertake the required analyses.** In the revised implementation plan, 18 months are allotted from the effective date of the standard until R2 is enforceable. The SDT believes this proposed timeline is achievable.
- **Requirement R5. Some commenters indicated that 18 months was not enough time to model GIC flows.** The SDT agrees with the comments and has changed the proposed effective date to 24 months (from 18 months).
- **Requirement R6. Some commenters indicated that 36 months was not enough time to perform the thermal assessments, given the need to acquire capability information from the transformer manufacturers and the need to perform this task for what is, at this time, an unknown number of transformers.** The SDT agrees with the comments and has changed the proposed effective date to 48 months (from 36 months).
- **Requirements R3, R4, and R7. Comments received indicated that 48 months was not enough time to perform the GMD vulnerability assessment and develop a Corrective Action Plan, given that the process will be new to the planners, require data that is not currently available to planners, and dependent upon pre-requisite steps that would be performed by others.** The SDT agrees with the comments and has changed the proposed effective date to 60 months (from 48 months).
- **Shorten implementation. Some commenters recommended reducing the timeline. A commenter stated that the timeline should include implementation of corrective action.** The SDT believes the revised implementation plan is appropriate for the planning approach taken in TPL-007.
- **Florida entities stated a variance or delay was needed due to availability of a Florida earth models.** Researchers at U.S. Geological Survey have developed a model for Florida which should enable entities to conduct GMD Vulnerability Assessments within the proposed Implementation Plan.

Organization	Yes or No	Question 4 Comment
PacifiCorp	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.
Associated Electric Cooperative, Inc. - JRO00088	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.
Northeast Power Coordinating Council	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

Organization	Yes or No	Question 4 Comment
		been procured, the simulation time and development of the Corrective Action Plans would probably take longer than prescribed in the standard.
Foundation for Resilient Societies	No	We do not agree with the approach for the transformer thermal assessments. The timeline could be shortened by simply installing hardware blocking devices.
ACES Standards Collaborators	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.
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	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

Organization	Yes or No	Question 4 Comment
		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.
Arizona Public Service Company	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.
SERC Planning Standards Subcommittee Ameren	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

Organization	Yes or No	Question 4 Comment
		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.
Colorado Springs Utilities	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”?
MRO NERC Standards Review Forum MidAmerican Energy	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.
DTE Electric	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

Organization	Yes or No	Question 4 Comment
		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.
SPP Standards Review Group	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.
Nebraska Public Power District	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.

Organization	Yes or No	Question 4 Comment
ISO/RTO Council Standards Review Committee	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

Organization	Yes or No	Question 4 Comment
		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.
Bonneville Power Administration	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.
Exelon	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.
Hydro-Quebec TransEnergie	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.
Lincoln Electric System	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

Organization	Yes or No	Question 4 Comment
		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).
American Electric Power	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.
Emprimus	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.
James Madison University	No	The four-year timeline should include implementation of corrective action.
Minnkota Power Corporative	No	See NSRF Comments
Independent Electricity System Operator	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.
Oncor Electric LLC	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

Organization	Yes or No	Question 4 Comment
		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.
Georgia Transmission Corporation	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.
Tri-State Generation and Transmission Association, Inc.	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.
Dominion	Yes	

Organization	Yes or No	Question 4 Comment
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
Bureau of Reclamation	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.
Duke Energy	Yes	
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	Yes	
Massachusetts Attorney General	Yes	
Volkmann Consulting, Inc	Yes	
ladwp	Yes	

Organization	Yes or No	Question 4 Comment
Hydro One	Yes	The implementation period provides reasonable timelines.
American Transmission Company, LLC	Yes	
CenterPoint Energy	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.
Idaho Power	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	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.
Northeast Utilities	Yes	
LCRA Transmission Services Corporation	Yes	
Luminant Generation Company LLC	Yes	
Hydro One	Yes	The implementation period provides reasonable timelines.
Luminant Energy Company, LLC	Yes	
Public Service Enterprise Group	Yes	
Ingleside Cogeneration, LP	Yes	
Entergy Services, Inc.	Yes	
Pepco Holdings Inc	Yes	
Texas Reliability Entity	Yes	
Public Utiltiy District No. 1 of Cowlitz County, WA	Yes	However, this is uncharted territory. There should be provision to deal with any unanticipated difficulties.

5. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The SDT has made revisions to conform to changes in the proposed requirements. Do you agree with the VRFs and VSLs for TPL-007-1? If you do not agree, please explain why and provide recommended changes.**

Summary Consideration: The SDT has reviewed the comments and made changes as appropriate to the revised version of TPL-007-1. In addition, a VRF/VSL justification document has been included in the second posting.

The SDT changed the VRF of Requirement R6 (transformer thermal assessment) from High to Medium to better align with the NERC guidelines for VRFs. The SDT believes that failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System during a 100-year GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or Cascading.

The SDT added a fixed number to the Requirement R6 VSL categories to better describe the impact of noncompliance by a small entity.

Some commenters disagreed with assigning a High VRF to some or all of the requirements in TPL-007-1. They stated that the relative risk of a 1-in-100 year event did not justify a High VRF, or that the NERC guideline for a High VRF did not support the assignment. One commenter recommended a relative risk based on geographical latitude be considered in assigning VRFs. The SDT agrees that Requirement R6 (transformer thermal assessment) should be assigned a Medium VRF consistent with the NERC guidelines for VRFs and has revised the standard accordingly. The SDT does not agree that the VRF for Requirement R3 (GMD VA) and Requirement R7 (CAP) should be lowered. After examining these requirements against the NERC criterion for a High VRF assignment in the planning time horizon, the SDT concluded that failure to meet the requirement could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures during a 1-in-100 year GMD event. In applying the NERC VRF criteria to a requirement in the planning time horizon, the probability of the event being planned for is not a factor. Furthermore, guidelines for setting VRFs are established for consistent application across the Bulk-Power System which precludes basing VRFs on a specific geographic latitude.

Commenters recommended identifying elements or quantities for evaluation instead of pass/fail binary criteria. The SDT reviewed the VSLs and modified the VSL for Requirement R2 (GMD Models) to reflect degrees of compliance. Other VSLs were considered appropriate and consistent with NERC guidelines. The two requirements with pass/fail criteria cannot be separated into component elements or quantities, but rather should be taken as a whole to meet the reliability objective of the requirement. Furthermore, the VSL assignments are consistent with similar requirements in approved TPL-001-4. Pass/fail criteria are assigned a VSL of Severe in accordance with established guidelines.

A commenter recommended modifying the VSLs for Requirement R6 where the percentage basis had a magnified impact on smaller entities. The SDT agrees and has modified the VSLs in the revised standard accordingly. The degree of compliance is now assessed based on a percentage or fixed number as proposed.

Organization	Yes or No	Question 5 Comment
PacifiCorp	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.
Northeast Power Coordinating Council	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.
Foundation for Resilient Societies	No	Because the requirements of the standard are inadequate, we do not agree with the VRFs and VSLs.
ACES Standards Collaborators	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.
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	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

Organization	Yes or No	Question 5 Comment
		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.
Arizona Public Service Company	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.
Colorado Springs Utilities	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.
Bureau of Reclamation	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.
Emprimus	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.
Liberty Electric Power LLC	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

Organization	Yes or No	Question 5 Comment
		adding "for entities with fewer than ten identified transformers" and making one failure a medium VSL, two a high, more than two severe.
James Madison University	No	The standard is so weak that VRFs and VSLs are meaningless.
Georgia Transmission Corporation	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.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Dominion	Yes	
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	
MRO NERC Standards Review Forum	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	Yes	

Organization	Yes or No	Question 5 Comment
Company Generation; Southern Company Generation and Energy Marketing		
SPP Standards Review Group	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Massachusetts Attorney General	Yes	
Volkmann Consulting, Inc	Yes	
ladwp	Yes	
Hydro One	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Idaho Power	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5 Comment
Nebraska Public Power District	Yes	
Northeast Utilities	Yes	
LCRA Transmission Services Corporation	Yes	
American Electric Power	Yes	
Luminant Generation Company LLC	Yes	
Hydro One	Yes	
Luminant Energy Company, LLC	Yes	
Ingleside Cogeneration, LP	Yes	
Entergy Services, Inc.	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	
Minnkota Power Corporative	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric LLC	Yes	

Organization	Yes or No	Question 5 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Public Utiltiy District No. 1 of Cowlitz County, WA	Yes	
MidAmerican Energy	Yes	
DTE Electric		No comment
Xcel Energy		No comment.

6. **Mitigation Costs. In directing the development of reliability standards, FERC stated their expectation for NERC and the industry to consider the costs and benefits of mitigation measures to address GMD impacts. Proposed standard TPL-007-1 provides performance requirements but is not prescriptive on mitigation strategies or technologies, if any are necessary. The SDT believes this approach, which is consistent with other planning standards, is the most cost effective means to accomplish the directives in FERC's order. Do you agree with the SDT's approach? If you have any recommendations or cost information that you would like the SDT to consider please provide it here.**

Summary Consideration: The SDT thanks all commenters who provided input on mitigation costs. The proposed standard addresses the directives for a stage 2 GMD standard in FERC Order No. 779. In the order, FERC stated their expectation that "NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards (P.28)". The SDT has done so by selecting a planning approach for the reliability standard that allows responsible entities latitude to select mitigation from a variety of considerations which may include cost.

NERC Reliability Standards are technology-neutral and focus on the reliability objectives to be accomplished rather than the specific activities to be performed. The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies. Furthermore, GMD studies are necessary to achieve the objective of reliable operation during a benchmark GMD event. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations.

Organization	Yes or No	Question 6 Comment
PacifiCorp	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.

Organization	Yes or No	Question 6 Comment
Foundation for Resilient Societies	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.
ACES Standards Collaborators	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.
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	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

Organization	Yes or No	Question 6 Comment
		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.
Colorado Springs Utilities	No	SPP Comments only

Organization	Yes or No	Question 6 Comment
Bureau of Reclamation	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.
DTE Electric	No	More clarity is needed on who selects and funds GIC mitigation measures resulting from the thermal impact assessment.
SPP Standards Review Group Nebraska Public Power District	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.
Massachusetts Attorney General	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

Organization	Yes or No	Question 6 Comment
		measures that have extremely low value that could be better implemented elsewhere.
Volkmann Consulting, Inc	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.
Manitoba Hydro	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.

Organization	Yes or No	Question 6 Comment
Hydro-Quebec TransEnergie	No	Taking into account of the considerable potential expenses, without completed studies and assessment, the cost of mitigation measures can't be evaluated.
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.
Emprimus	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

Organization	Yes or No	Question 6 Comment
		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.
Public Service Enterprise Group	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.”
Ameren	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.
James Madison University	No	Standard should prescribe mitigation strategies to facilitate uniform protection against GMD.
Independent Electricity System Operator	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

Organization	Yes or No	Question 6 Comment
		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).
Northeast Power Coordinating Council	Yes	Hardware based mitigation technologies need to be further proven in test situations before mass deployment.
Arizona Public Service Company	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.
Dominion	Yes	
FirstEnergy Corp	Yes	
Tacoma Public Utilities	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 6 Comment
MRO NERC Standards Review Forum	Yes	
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	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon	Yes	
ladwp	Yes	
Hydro One	Yes	Mitigation technologies need to be further proven in test situations before mass deployment.
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 6 Comment
CenterPoint Energy	Yes	
Idaho Power	Yes	
Xcel Energy	Yes	
Northeast Utilities	Yes	
LCRA Transmission Services Corporation	Yes	
American Electric Power	Yes	
Hydro One	Yes	Hardware-based mitigation technologies need to be further proven in test situations before mass deployment.
Ingleside Cogeneration, LP	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.
Entergy Services, Inc.	Yes	
Pepco Holdings Inc	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 6 Comment
Minnkota Power Corporative	Yes	
Oncor Electric LLC	Yes	
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Public Utiltiy District No. 1 of Cowlitz County, WA	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.
Luminant Generation Company LLC		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.
Luminant Energy Company, LLC		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

Organization	Yes or No	Question 6 Comment
		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.

7. Are there any other concerns with the proposed standard or white papers that have not been covered by previous questions and comments? If so, please provide your feedback to the SDT.

Summary Consideration: The SDT thanks all commenters for providing feedback. As a result of stakeholder comments, the drafting team has revised performance requirements in Table 1 for added clarity. They have also updated Requirement R3 (previously R4) to give more flexibility to the PC for establishing acceptable voltage performance criteria rather than prescribing that this criteria be voltage limits. A summary of comments and the drafting team's response is provided. Several commenters referred to issues that were raised in other sections. SDT responses have not been duplicated here but are addressed in other sections:

- **Table 1 Footnote 4 (now 3). Some commenters questioned the implied limits on non-consequential load loss as a means to meeting table 1 performance.** The SDT has revised the guidance in table 1. The new footnote (Footnote 3) reads: 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.
- **Performance Criteria. Commenters recommended modifying Requirement R4 (now R3; criteria for steady state voltage limits) to allow for future developments in determining voltage stability during a severe GMD event. A commenter recommended the SDT consider additional language to describe what an 'acceptable limit' for steady state voltages would be as specified in Table 1 note d. The SDT supports broadening the voltage criteria requirement (Requirement R3 in the revised standard) to allow PCs to establish criteria for meeting specified performance. The requirement now reads: R3.** Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1.
- **Technical guidance. Commenters asked for additional guidance to be included in the standard or application guidelines, including grounding grid resistance in the GIC model, modeling neighboring systems, and assessing harmonic impacts.** The SDT believes the proposed standard and application guidelines provide sufficient detail to understand the requirements. Like other planning standards, it is not possible or beneficial for the standard and application guidelines to include all of the technical details necessary to cover every implementation of the standard for every entity. The standard specifies the assessment parameters and System performance requirements without being technically prescriptive. The SDT believes technical guidance such as may be found in the GMD Task Force guides and SDT white papers will support performance of the requirements by all applicable entities.
- **Requirements for updating the GMD Vulnerability Assessment. Commenters asked if updates to the GMD VA were required for configuration changes such as the installation of a new line or transformer. Commenters recommended alternate periodicities including a 120-month periodicity or a 36-month periodicity instead of the 60-month periodicity in the proposed standard.** The SDT believes conducting GMD Vulnerability Assessments with a 60-month periodicity will provide the necessary

safeguards for the power system against a 100-year GMD event. They do not believe network changes within this periodicity would significantly change the result for the assessment period or create a vulnerability.

- **Recurrence of Requirement R5 and R6. A commenter recommended adding a subpart addressing recurrence.** The standard specifies a 60-month periodicity for the overall process of the assessments required in TPL-007. Planning entities need the thermal impact assessment information for the GMD Vulnerability Assessment and providing the GIC flow information in Requirement R5 is a necessary step. Owners are required to provide results of the thermal impact assessment with 24 months of receiving GIC flow information. The SDT believes the proposed addition of a periodicity to these requirements is administrative and unnecessary.
- **Use of third-party vendors or consultants. A commenter recommended modifying requirements to allow for a responsible entity to use a third-party.** The standard as written does not preclude the use of third-parties to perform analysis.
- **Assessment iterations to evaluate mitigation. A commenter recommended clarifying the standard to address the necessary time for performing iterations of the GMD Vulnerability Assessment to evaluate mitigation.** The SDT expects that planning entities will factor this into their assessment timeline and does not support a prescriptive time limit. They recognize that some entities will require one or more iterations, while others will not.
- **Underground feeders. A commenter asserted that underground feeders were not affected by GIC and recommended development of a scaling factor for to account for these in power systems.** The SDT recognizes that underground cables are affected by GIC; The standard is not prescriptive in how to model system components, leaving such modeling approaches to the planning entity.
- **Functional Entities. A commenter stated that operating entities needed to be included in the applicability to comply with the FERC Order. A commenter stated that the RC needed to be included as an applicable entity to ensure interconnection-wide perspective on transmission planning.** The SDT has identified appropriate applicable entities for the planning approach consistent with the NERC Functional Model. FERC took no position in the final rule on which entities were to be applicable (P. 82). The RC is not an applicable entity in the planning standard, but they will receive information as a result of planning studies conducted in TPL-007 in accordance with Requirement R7. The RC does not have planning responsibilities according to the NERC Functional Model. The standard as written does not preclude a regional or interconnection-wide study. Applicable Functional entities retain responsibility for requirements of the standard.
- **Applicable Facilities. A commenter recommended including autotransformers in the applicability. A commenter asked if wye-grounded includes solidly wye-grounded, low impedance wye grounded, and high impedance wye grounded windings.** Yes, these power transformers are included in the applicability section.
- **GIC Monitoring. Commenters stated that the standard does not include requirements to monitor GIC, archive data, or validate models using GIC data.** NERC standards do not address installation of specific equipment for any power system application.

Planning Standards define the required reliability outcomes and leave the methods, tools and equipment to the registered entities to determine and implement.

- **Audit, review, or approval of GMD Vulnerability Assessment. A commenter stated that there is no requirement for audit, review, or external approval of GMD Vulnerability Assessment methodology, and that there is no certification process for modeling software.** TPL-007 is in accordance with existing NERC standards related to planning. The techniques used to produce the GMD Vulnerability Assessments are described in various technical guides and are based on the best available information; therefore, the compliance program focuses on fulfilling the requirements of the standard. Planning standards define the required reliability outcomes and leave the methods, tools and equipment to the registered entities to determine and implement.
- **Corrective Action Plans (CAP) requirements. A commenter stated that the proposed standard does not meet FERC order because it does not prohibit CAP from being limited to Operating Procedures or training alone. Commenters recommended modifying Requirement R7 to clearly include a requirement to implement or complete the CAP.** The directive in para 79 of FERC order 779 is met by in Requirement R7 part 7.1 which lists actions which may be included in CAP to achieve acceptable System performance. In the order FERC stated "we clarify that if the GMD vulnerability assessments in the Second Stage GMD Reliability Standards identify potential GMD impacts, while the development of the required mitigation plan cannot be limited to considering operational procedures or enhanced training alone, operational procedures and enhanced training may be sufficient if that is verified by the vulnerability assessments. (P.82)" CAP must include a timetable for implementation as defined in the NERC Glossary.
- **Other functional entity roles in thermal assessments. A commenter recommended that the GO and TO obtain planning entity concurrence on the thermal assessment technique selected in order to avoid an overly conservative model being used. A commenter suggested changing the applicable entity for thermal assessment to the GOP and TOP.** The SDT has assigned responsibility for conducting thermal assessments to owners, which is consistent with the NERC functional model. Asset owners are not precluded from consulting with planning entities during the process, but such consultation is optional.
- **Evidence retention. A commenter proposed that the standard should require data to be retained in perpetuity. A commenter recommended retaining evidence of Requirement R7 (CAP) for as long as the CAP was being implemented.** The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance.
- **Administrative (Paragraph 81) Requirements. A commenter recommended removing Requirements R3 (GMD VA) and R7 (Corrective Action Plan) for Paragraph 81 criteria.** The SDT believes these requirements fulfill a reliability objective and are not purely administrative. GMD Vulnerability Assessments must be updated periodically to account for changes and ensure the meets performance requirements. This is consistent with the FERC order which requires 'initial and ongoing assessments' (P. 2)

The SDT also recognizes the reliability benefit in requiring entities to provide CAP to adjacent planning entities, RCs, and other entities identified in the CAP Several commenters have highlighted regional nature of GMD and the need to share information so that the actions of one entity do not negatively impact those of another. R7 part 7.3 provides this obligation.

- **Technical basis for standards. Commenters stated that assessment techniques, models, or tools were not mature enough for a NERC Reliability Standard.** The SDT believes the proposed standard meets the FERC directives and is a technically sound approach to assessing the impact of GMD. The approach outlined in the standard reflects practices that are currently employed and is consistent with the work of the NERC GMD Task Force.
- **Editorial corrections. Commenters provided various editorial corrections that have been included in the revision.**

Organization	Yes or No	Question 7 Comment
Associated Electric Cooperative, Inc. - JRO00088	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.
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)	No	

Organization	Yes or No	Question 7 Comment
FirstEnergy Corp	No	
Duke Energy	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.
Massachusetts Attorney General	No	
ladwp	No	
American Transmission Company, LLC	No	
CenterPoint Energy	No	
Idaho Power	No	
Nebraska Public Power District	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

Organization	Yes or No	Question 7 Comment
		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.
LCRA Transmission Services Corporation	No	
Emprimus	No	
Public Service Enterprise Group	No	
Pepco Holdings Inc	No	
Georgia Transmission Corporation	No	
PacifiCorp	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

Organization	Yes or No	Question 7 Comment
		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
Northeast Power Coordinating Council	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

Organization	Yes or No	Question 7 Comment
		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

Organization	Yes or No	Question 7 Comment
		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.
Foundation for Resilient Societies	Yes	Comments on TPL-007-11. 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...."

Organization	Yes or No	Question 7 Comment
		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.

Organization	Yes or No	Question 7 Comment
ACES Standards Collaborators	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.
Arizona Public Service Company	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.
Dominion	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

Organization	Yes or No	Question 7 Comment
		Compliance Elements:Page 21 of 24, Lower VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalizedPage 21 of 24, High VSL column, Amperes should not be capitalizedPage 21 of 24, Severe VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalizedPage 21 of 24, Moderate VSL column, Amperes should not be capitalized
Tacoma Public Utilities	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.
SERC Planning Standards Subcommittee	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

Organization	Yes or No	Question 7 Comment
		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.
Seattle City Light	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

Organization	Yes or No	Question 7 Comment
		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.
Colorado Springs Utilities	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.
Bureau of Reclamation	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

Organization	Yes or No	Question 7 Comment
		interconnection-wide perspective on transmission planning for geomagnetic disturbance events.
MRO NERC Standards Review Forum	Yes	
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	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”).

Organization	Yes or No	Question 7 Comment
DTE Electric	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.
SPP Standards Review Group	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 ‘Â°C’ following ‘110’.
ISO/RTO Council Standards Review Committee	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

Organization	Yes or No	Question 7 Comment
		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

Organization	Yes or No	Question 7 Comment
		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.
Bonneville Power Administration	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.
Exelon	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

Organization	Yes or No	Question 7 Comment
		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?
Volkmann Consulting, Inc	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

Organization	Yes or No	Question 7 Comment
		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.
Wisconsin Electric Power Company	Yes	The SDT needs to correct the standard language as identified at the technical conference on 7/17/14.
Hydro One	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.
Xcel Energy	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.
ReliabilityFirst	Yes	ReliabilityFirst supplies the following comments for consideration:1. Applicability Sectiona. 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

Organization	Yes or No	Question 7 Comment
		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"

Organization	Yes or No	Question 7 Comment
		statements. Since Table 1 is performance requirements, should these statements in Footnote 4 be “shall” statements?
Manitoba Hydro	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.
Hydro-Quebec TransEnergie	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.
Northeast Utilities	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.
American Electric Power	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

Organization	Yes or No	Question 7 Comment
		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."
Luminant Generation Company LLC Luminant Energy Company LLC	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.
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,

Organization	Yes or No	Question 7 Comment
		which states Voltage collapse, Cascading and uncontrolled islanding shall not occur, which indicates further analysis is warranted.
Hydro One	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.
Entergy Services, Inc.	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.
Texas Reliability Entity	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

Organization	Yes or No	Question 7 Comment
		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

Organization	Yes or No	Question 7 Comment
		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.
Ameren	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

Organization	Yes or No	Question 7 Comment
		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.
Liberty Electric Power LLC	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.
James Madison University	Yes	Comments on NERC’s draft GMD Benchmark ReportI 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

Organization	Yes or No	Question 7 Comment
		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-

Organization	Yes or No	Question 7 Comment
		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. BakerProfessor Emeritus and Former Director, Institute for Infrastructure and Information Assurance, James Madison UniversityCongressional EMP CommissionAttachment: Detailed comments on Project 2013-03 Benchmark Geomagnetic Disturbance Event Descriptionâ€ƒAttachment 1NERC Project 2013-03

Organization	Yes or No	Question 7 Comment
		Benchmark Geomagnetic Disturbance Event DescriptionDetailed CommentsGeorge H. Baker and Charles T.C. Moo 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. ï,§ 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.ï,§ The 8kv/m level is lower than historically measured peak GMD field values.ï,§ 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.ï,§ 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. ï,§ Explain why you see a correlated relationship between DST and storm strength.ï,§ Again, why have you not referenced the 1921 Railroad Storm?ï,§ 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

Organization	Yes or No	Question 7 Comment
		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.
Minnkota Power Corporative	Yes	The Definition in TPL-007-1 for Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment refers to “voltage collapse, Cascading or localized

Organization	Yes or No	Question 7 Comment
		damage of equipment." In Table 1-Steady-State Planning Events refers to "Cascading and uncontrolled islanding shall not occur." Why are they different?
Independent Electricity System Operator	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.
Oncor Electric LLC	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.
Tri-State Generation and Transmission Association, Inc.	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.
Public Utiltiy District No. 1 of Cowlitz County, WA	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.

Organization	Yes or No	Question 7 Comment
MidAmerican Energy	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.
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.
PPL NERC Registered Affiliates		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

Organization	Yes or No	Question 7 Comment
		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.
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: o Regional level developed model will provide a better considered analysis than by the individual PCs, TOs, or GOs; o Study results will be better analyzed and interpreted by equipment owners instead of individual entities’ interpretation of the results; o A single report produces for all Regional members instead of individual report from each Members could lead to inconsistent

Organization	Yes or No	Question 7 Comment
		results/conclusions/recommendations; o Entities' resources can be significantly reduced by participating in Regional process instead of perform the numerours studies that are currently contemplated in the standard.

END OF REPORT

Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard

A White Paper by:

John G. Kappenman, Storm Analysis Consultants

and

Dr. Willam A. Radasky, Metatech Corporation

July 30, 2014

Executive Summary

The analysis of the US electric power grid vulnerability to geomagnetic storms was originally conducted as part of the work performed by Metatech Corporation for the Congressional Appointed US EMP Commission, which started their investigations in late 2001. In subsequent work performed for the US Federal Energy Regulatory Commission, a detailed report was released in 2010 of the findings[11]. In October 2012, the FERC ordered the US electric power industry via their standards development organization NERC to develop new standards addressing the impacts of a geomagnetic disturbance to the electric power grid. NERC has now developed a draft standard and has provided limited details on the technical justifications for these standards in a recent NERC White Paper[22].

The most important purpose of design standards is to protect society from the consequences of impacts to vulnerable and critical systems important to society. To perform this function the standards must accurately describe the environment. Such environment design standards are used in all aspects of society to protect against severe excursions of nature that could impact vulnerable systems: floods, hurricanes, fire codes, etc., are relevant examples. In this case, an accurate characterization of the extremes of the geomagnetic storm environment needs to be provided so that power system vulnerabilities against these environments can be accurately assessed. A level that is arbitrarily too low would not allow proper assessment of vulnerability and ultimately would lead to inadequate safeguards that could pose broad consequences to society.

However from our initial reviews of the NERC Draft Standard, the concern was that the levels suggested by NERC were unusually low compared to both recorded disturbances as well as from prior studies. Therefore this white paper will provide a more rigorous review of the NERC benchmark levels. NERC had noted that model validations were not undertaken because direct measurements of geo-electric fields had not been routinely performed anyway in the US. In contrast, Metatech had performed extensive geo-electric field measurement campaigns over decades for storms in Northern Minnesota and had developed validated models for many locations across the US in the course of prior investigations of US power grid vulnerability[3]. Further, various independent observers to the NERC GMD tasks force meetings had urged NERC to collect decades of GIC observations performed by EPRI and independently by power companies as these data could be readily converted to geo-electric fields via simple techniques to provide the basis for validation studies across the US. None of these actions were taken by the NERC GMD Task Force.

It needs to be pointed out that GIC measurements are important witnesses and their evidence is not being considered by the NERC GMD Task Force in the development of these standards. GIC observations provide direct evidence of all of the uncertain and variable parameters including the deep Earth ground response to the driving geomagnetic disturbance environment. Because the GIC measurement is also obtained from the power grid itself, it incorporates all of the meso-scale coupling of the disturbance environments to the assets themselves and the overlying circuit topology that needs

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[1] *Geomagnetic Storms and Their Impacts on the U.S. Power Grid* (**Meta-R-319**), John Kappenman, Metatech Corporation, January 2010. Via weblink from Oak Ridge National Lab, *wttp://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml*

[2] NERC Benchmark Geomagnetic Disturbance Event Description, *http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Benchmark_GMD_Event_April21_2.pdf*

[3] Radasky, W. A., M. A. Messier, J. G. Kappenman, S. Norr and R. Parenteau, "Presentation and Analysis of Geomagnetic Storm Signals at High Data Rates", IEEE International Symposium on EMC, August 1993, pp. 156-157.

to be assessed. Separate discreet measurements of geo-electric fields are usually done over short baseline asset arrays which may not accurately characterize the real meso-scale interdependencies that need to be understood. The only challenge is to interpret what the GIC measurement is attempting to tell us, and fortunately this can be readily revealed with only a rudimentary understanding of Ohm's Law, geometry and circuit analysis methods, a tool set that are common electrical engineering techniques. Essentially the problem reduces to: *"if we know the I (or GIC) and we know the R and topology of the circuit, then Ohm's law tells us what the V or geo-electric field was that created that GIC"*. Further since we know the resistance and locations of power system assets with high accuracy, we can also derive the geo-electric field with equally high certainty. These techniques allow superior characterization of deep Earth ground response and can be done immediately across much of the US if GIC measurements were made available. Further these deep Earth ground responses are based upon geological processes and do not change rapidly over time. Therefore even measurements from one storm event can characterize a region. Hence this is a powerful tool for improving the accuracy of models and allows for the development of accurate forward looking standards that are needed to evaluate to high storm intensity levels that have not been measured or yet experienced on present day power grids. Unfortunately this tool has not been utilized by any of the participants in the NERC Standard development process.

It has been noted that the NERC GMD Task Force has adopted geo-electric field modelling techniques that have been previously developed at FMI and are now utilized at NRCan. The same FMI techniques were also integrated into the NASA-CCMC modeling environments and that as development and testing of US physiographic regional ground models were developed, efforts were also undertaken by the USGS and the NOAA SWPC to make sure their geo-electric field models were fully harmonized and able to produce uniform results. However, it appears that none of these organizations really did any analysis to determine if the results being produced were at all accurate in the first place. For example when recently inquired, NRCan indicated they will perhaps begin capturing geo-electric field measurements later this year to validate the base NERC Shield region ground model, a model which provides a conversion for all other ground models. In looking at prior publications of the geo-electric field model carried out in other world locations, it was apparent that the model was greatly and uniformly under-predicting for intense portions of the storms, which are the most important parameters that need to be accurately understood.

In order to examine this more fully, this white paper will provide the results of our recent independent assessment of the NERC geo-electric field and ground models and the draft standard that flows from this foundation. Our findings can be concisely summarized as follows:

- Using the very limited but publicly available GIC measurements, it can be shown how important geo-electric fields over meso-scale regions can be characterized and that these measurements can be accurately assessed using the certainty of Ohm's Law. This provides a very strict constraint on what the minimum geo-electric field levels are during a storm event.

- When comparing these actual geo-electric fields with NERC model derived geo-electric fields, the comparisons show a systematic under-prediction in all cases of the geo-electric field by the NERC model. In the cases examined, the under prediction is particularly a problem for the rapid rates of change of the geomagnetic field (the most important portions of the storm events) and produce errors that range from factor of ~2 to over factor of ~5 understatement of intensity by the NERC models compared to actual geo-electric field measurements. These are enormous errors and are not at all suitable to attempt to embed into Federally-approved design standards.

- These enormous model errors also call into question many of the foundation findings of the NERC GMD draft standard. The flawed geo-electric field model was used to develop the peak geo-electric field levels of the Benchmark model proposed in the standard. Since this model understates the actual geo-electric field intensity for small storms by a factor of 2 to 5, it would also understate the maximum geo-electric field by similar or perhaps even larger levels. Therefore this flaw is entirely integrated into the NERC Draft Standard and its resulting directives are not valid and need to be corrected.

The findings here are also not simply a matter of whether the NERC model agrees with the results of the Metatech model. Rather the important issue is the degree that the NERC model disagrees with actual geo-electric field measurements from actual storm events. These actual measurements are also confirmed within very strict tolerances via Ohm's Law, a fundamental law of nature. The results that the NERC model has provided are not reliable, and efforts by NERC to convince otherwise and that utilization of GIC data cannot be done are simply misplaced. Actual data provides an ultimate check on unverified models and can be more effectively utilized to guide standard development than models because as Richard Feynman once noted; "Nature cannot be fooled"!

Introduction to NERC Model Evaluation and Validation Overview

A series of case study examples will be provided in this White Paper to illustrate the evaluation of geo-electric fields derived from GIC measurements across the US electric power grid. These derived geo-electric field results will then be compared to the NERC estimated geo-electric fields for the same storm events and scenarios. There are an important number of underlying principles to this analysis that can be summarized as follows:

- Using past storms and by modeling detailed power networks and comparing to GIC measurements at particular locations is the best way to validate overall storm-phenomena/power grid models. It accounts for the "interpolation" of the incident measured B-fields (including the angular rotation of the fields with time), the accuracy of the ground model used, the coupling to the power network, and the computation of the current flow at the measurement point.

- Experience has shown that over times of minutes, the geomagnetic field will rotate its direction and therefore every transformer in a network will have a sensitivity to particular vector orientations of the field, and the maximum current measured at a given transformer location will be a function of the rate of change intensity of the geomagnetic field, the resulting geo-electric field this causes and the angle of the field as it changes over the storm event. This is why the rate of change (dB/dt) and GIC at a single transformer will not scale perfectly with the maximum value of dB/dt, but taking into consideration all of these topology and orientation factors, a highly accurate forensic analysis can be performed.

- Geomagnetic storms are not steady state events, rather they are events with aperiodic extreme impulsive disturbances that can occur over many hours or days duration. Modeling these events to derive a geo-electric field is challenging but readily achievable. Since these events are time domain problems, modeling solutions using time-domain methods are recommended. The NERC modeling methods that will be evaluated here have generally been developed using Fourier transform frequency domain methods. In these implementations of Fourier methods, the primary question is the accuracy in dealing with the phase of the Fourier transforms.

- When referring to impulsive geomagnetic field disturbance events, these are typically multiple discrete events with times of several minutes. Note that the collapse of the Quebec power network in March 1989 occurred in 93 seconds. Clearly times of only a few minutes are important and it is vital that the geo-electric field intensity of these transients be accurately portrayed and not understated in a Design Standard type document. For example, a 10 meter dyke defined by the standard does no good, if the actual Tsunami height is 15 meters. Any efforts to claim that models that depict some satisfactory averaging over extended time periods as being sufficient must be vigorously refuted, as these peak inflection points are the most vital aspects of the storm environments that must be accurately determined.

Simulation Model Validation – Maine Grid Examples

In the analysis carried out for the FERC Meta-R-319 report, extensive efforts were undertaken to verify that the simulation models for the US power grid were providing sufficiently accurate results. One of the primary approaches that were utilized to test these models were to perform simulations for forensic analysis purposes and to compare the results with discrete measurements that were available.

One of the forensic simulations was conducted on the Maine grid and provided important verification of the ability of the model in that portion of the US grid to produce accurate estimates. Figure 1 provides a plot of the results of this simulation showing the "Calculated" versus "Measured" GIC (geomagnetically induced current) at the Chester Maine 345kV transformer. This was for a storm which occurred on May 4, 1998 and was driven by the large scale storm conditions as shown in Figure 2.

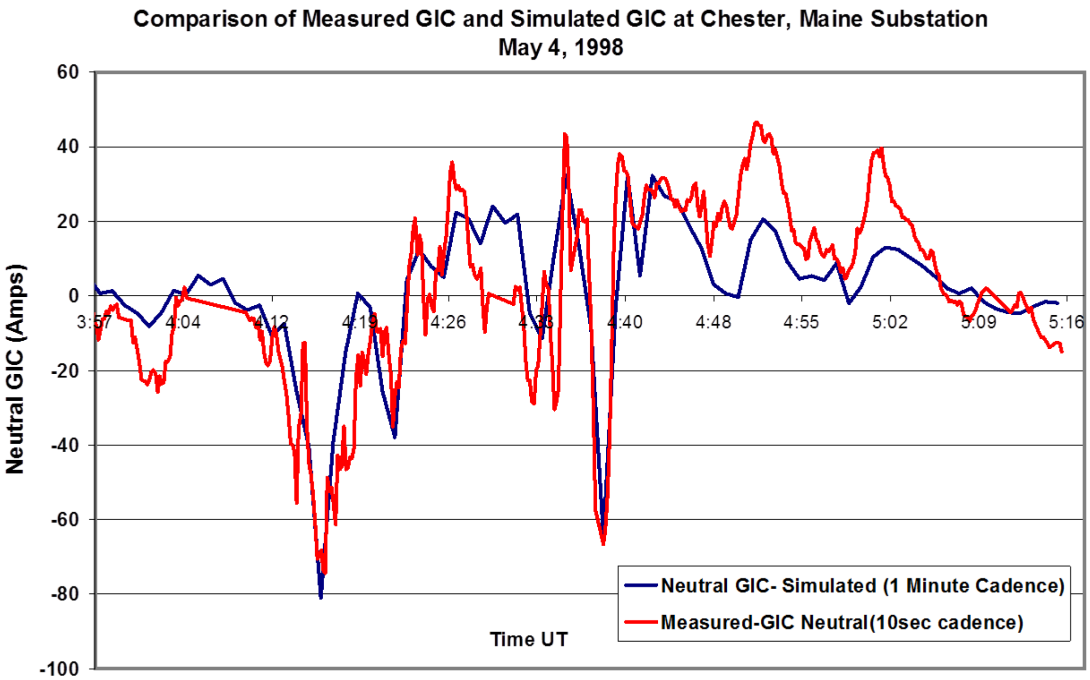

Figure 1 – Plot showing comparison of Simulated versus Measured GIC at Chester Maine 345kV transformer for May 4, 1998 geomagnetic storm. (Source – Meta-R-319)

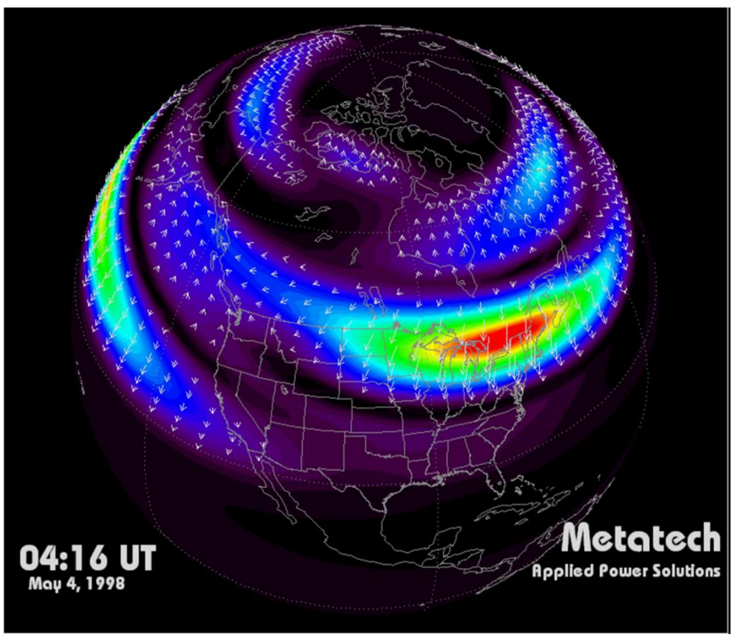

Figure 2 – Map of Geomagnetic Disturbance conditions at 4:16UT during May 4, 1998 storm. (Source – Meta-R-319)

The results in Figure 1 provide a comparison between high sample rate measured GIC (~10 second cadence) versus storm simulations that were limited to 1 minute cadence geomagnetic observatory data inputs (B-fields). Due to this limitation of inputs to the model, the model would not be able to reproduce all of the small scale high frequency variations shown in the measured data. However, the simulation does provide very good accuracy and agreement on major spikes in GIC observed, the most important portion of the simulation results that need to be validated. Figure 3 provides a wider view of the impact of the storm in terms of other GIC flow conditions in the Maine and New England region electric power grid, this is provided at time 4:16UT.

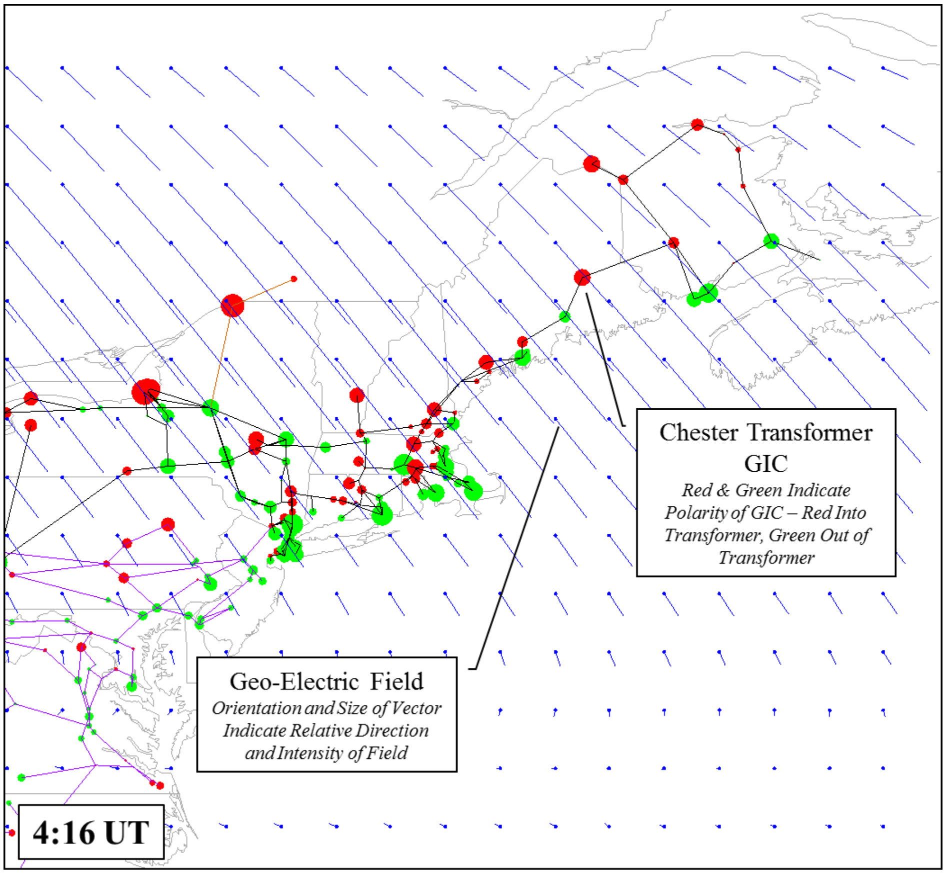

Figure 3 – GIC flows and disturbance conditions in Maine/New England grid at 4:16UT, May 4, 1998. (Source – Meta-R-319)

As this illustration shows, the Chester GIC flow is shown along with comparable GIC flows in a number of other locations in the regional power grid at one minute in time. In addition to impacts to the New England grid, extensive power system impacts were also observed to voltage regulation in upstate New York region due to storm. In this map, the intensity and polarity of GIC flows are depicted by red or green balls and their size, the larger the ball the larger the GIC flow and the danger it presents to the transformer and grid. Also shown are the blue vector arrows which are the orientation and intensity of the geo-electric field which couples to the topology of the electric grid and produces the GIC flow patterns that develop in the grid. It is noted that during the period of this storm, the electric fields rotated and all transformers in the grid would experience a variation in the pattern of GIC flows.

Considerable scientific and engineering examination has been performed since the release of the Meta-R-319 report; the report and other subsequent examinations are in close agreement on a number of important parameters of future severe geomagnetic storm threat conditions. For example, it is now well-accepted that severe storm intensity disturbance intensity can reach level of 5000 nT/min at the latitudes of the Maine power grid. NRCan now provides estimates of geo-electric fields for the nearby Ottawa observatory for storms including the May 4, 1998 storm. The ability therefore exists to do cross-validations with this and other proposed NERC ground models and geo-electric field calculation methods.

Observations of GIC at the Chester Maine substation also provide important observational confirmations that allow empirical projection of GIC levels that are plausible at more severe storm intensities. Earlier this year, the Maine electric utilities provided a limited summary of peak GIC observations from their Chester transformer and storm dates to the Maine Legislature. Figure 4 provides a graphical summary that was derived of the peak GIC and peak disturbance intensities (in nT/min) observed at the Ottawa Canada geomagnetic observatory for a number of reported events. The Maine utilities did not provide accurate time stamps (just date only), so that limits some of the ability to accurately correlate disturbance intensity to GIC peaks as the knowledge of timing is extremely coarse. Also since the Ottawa observatory is approximately 550km west of Chester, there is some uncertainty to local storm intensity specifics near Chester. However as shown, there are clear trend lines and uncertainty bounding of the level of GIC and how the GIC increases for increasing storm intensity. This trend line is quite revealing even with all of the previously mentioned uncertainties on the spatial and temporal aspects of the threat environments.

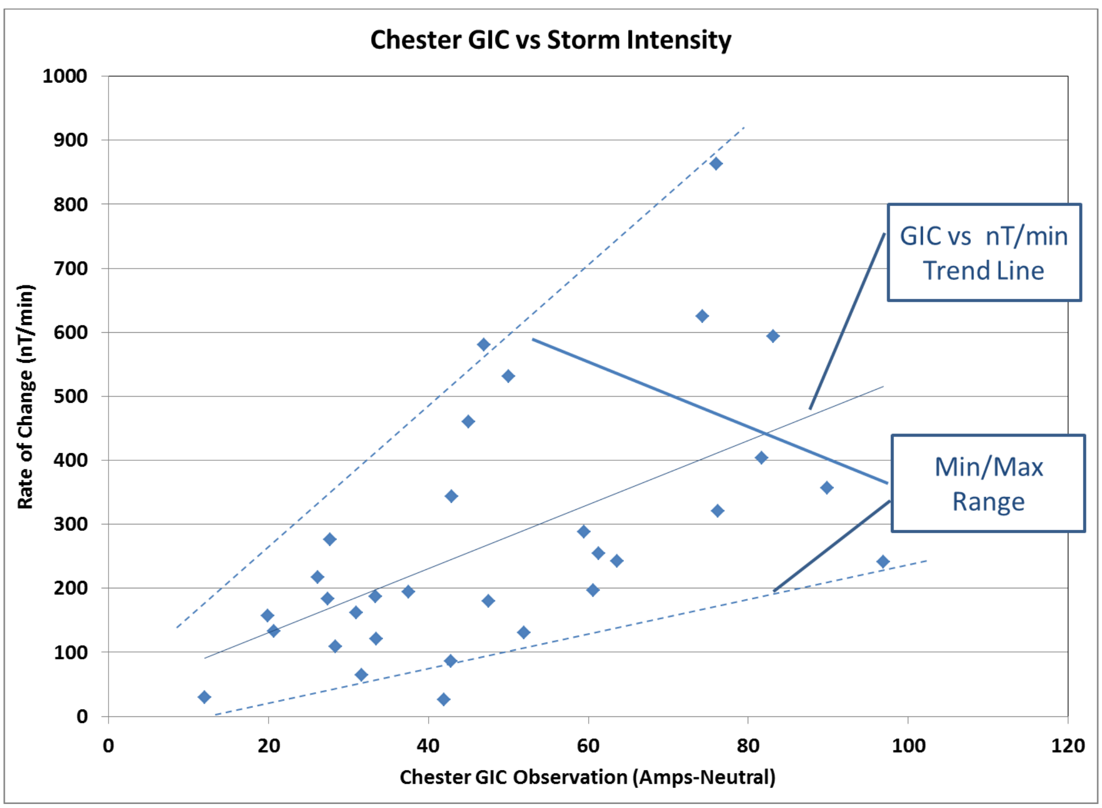

Figure 4 – GIC versus Storm Intensity (nT/min) from multiple observed GIC storm events at Chester Transformer, in this case the GIC timing is extremely coarse.

At higher storm intensities, the geo-electric field increases and if only intensity changes (as opposed to spectral content), then the increase in geo-electric field and resulting GIC will be linear. Because storm intensity for very severe storms can reach ~5000 nT/min, this graph can be linearly extended to project the range of GIC flows in the Chester transformer for these more extreme threat conditions. Figure 5 provides a plot similar to that in Figure 4, only with linear extensions of the GIC flow that this observational data estimates.

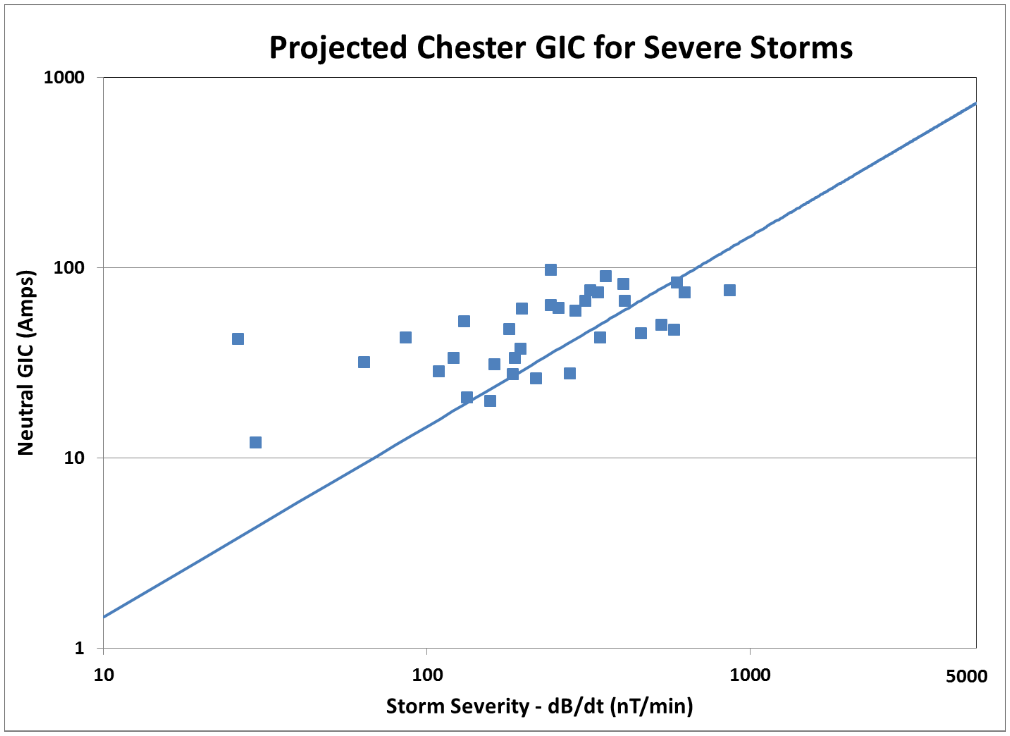

Figure 5 – Projected Chester GIC flow for storm intensity increasing to ~5000 nT/min.

Using these data plotting techniques with the previously noted uncertainties, a more detailed examination can be performed for one of the specific storm events which occurred on May 4, 1998. Figure 6 provides again the earlier described GIC plots from Figure 1. Two particularly important peak times are also highlighted on this plot at 4:16UT and 4:39UT where the recorded GIC reaches peaks respectively of -74.3 Amps and -66.6 Amps. These comparisons also show very close agreement with the simulation model results as well. Therefore the peak data points can be more explicitly examined in detail, as a comparison to how GIC vs dB/dt was plotted in Figure 4. In addition to this GIC observation data, there was also dB/dt data observed from a local magnetometer for this storm, which also greatly reduces the uncertainty of the threat environment.

Having all of this data available will aid in utilizing the power system itself as an antenna that can help resolve the geo-electric field intensity that the complex composition of ground strata generates during this storm event. Further once this response is empirically established, this same ground response can be reliably utilized to project to higher storm intensity and therefore higher GIC levels. This provides a blended effort of model and observational data to extract details on how the same grid and ground strata would behave at higher storm intensity levels. One of the advantages that exists in the modeling of the circuits of the transmission networks are that the resistive impedances of transmission lines and transformers (which are the key GIC flow paths) are very well known and have small uncertainty errors. It is also known that the Chester transformer is non-auto, so GIC flow in the neutral also defines the GIC per phase. There is also no doubt about the locations of assets within the circuit topology. Finally, station grounding resistance can also be determined to relatively high certainty as well. In comparison, ground response as has been previously published in the Meta-R-319 report can vary over large ranges, as much as a factor of 6. Therefore direct observations of ground response are highly important and GIC measurements, as will be discussed, provide an excellent proxy or geophysical data that can be used to derive the complex behavior characteristics of the ground strata. This set of understandings can be applied as a tool to significantly bound this major area of uncertainty.

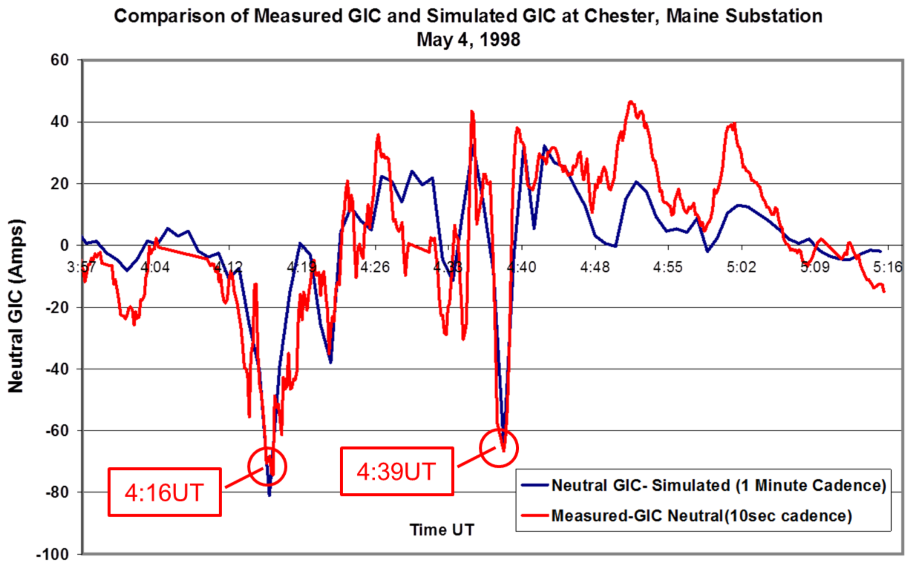

Figure 6 – GIC observation at times 4:16 & 4:39 UT that can be examined in further detail.

Network Model and Calculation of Chester GIC for 1 V/km Geo-Electric Field

Using the Maine region power grid model of the EHV grid, it is possible to examine what the GIC flow would be at the Chester transformer for a specified geo-electric field intensity of 1 V/km. This specified GIC is an intrinsic and precise characteristic of the network that will provide a useful yardstick to calibrate against for actual GIC flows that occurred and from that a more highly bounded geo-electric field intensity range can be determined at this location. Figure 7 provides a plot of the GIC flow in the Chester transformer for a 1 V/km geo-electric field. Since the topology of the transmission network also greatly determines the resulting GIC, this calculation is performed for a full 360 degree rotation of the orientation of the 1 V/km field.

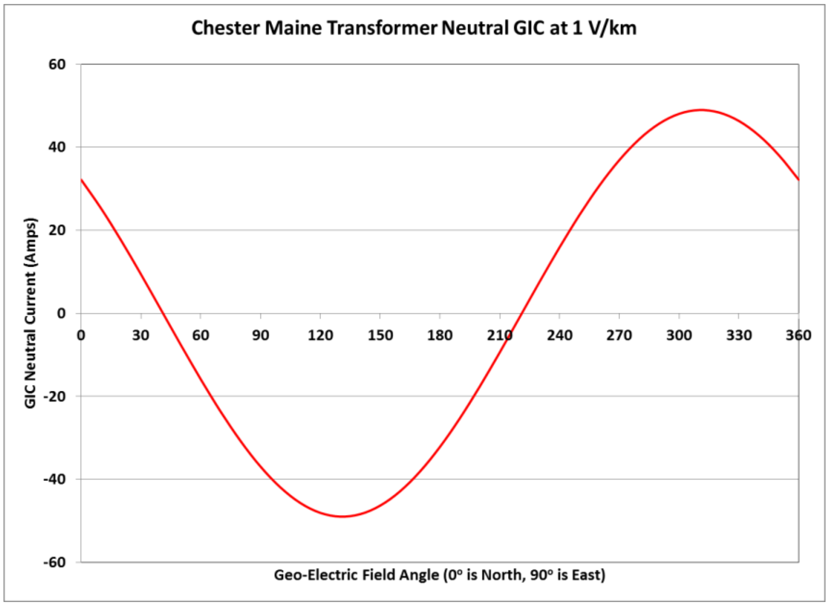

Figure 7 – GIC flow at Chester transformer neutral for 1 V/km geo-electric field at various orientation angles.

As the plot in Figure 7 shows, the peak GIC flow at this location is ~49 Amps which occurs at the 130° and 310° angular orientations of the 1 V/km field.

While the GIC to 1 V/km relationship in Figure 7 is developed from a detailed network model, there are also much simpler methods using a limited knowledge of a portion of the local transmission network that can be used to check the accuracy of the model. This involves a simple circuit analysis to derive the resistance and orientation specifics of just the two major transmission lines connecting to Chester. Each of the two 345kV lines connecting to Chester (from Chester-Orrington and from Chester to Keswick New Brunswick) is shown in the map of Figure 8.

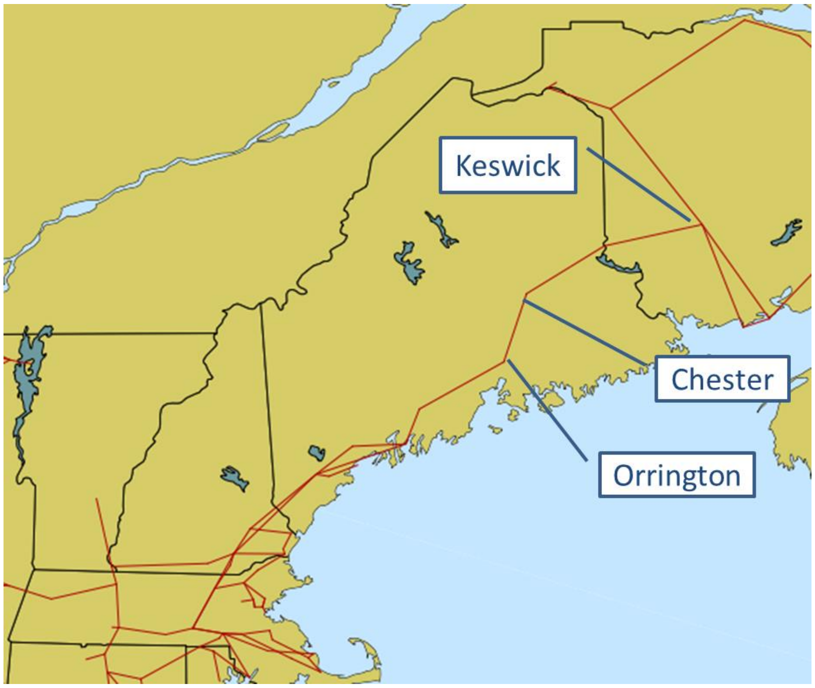

Figure 8 - Map of Chester Maine and 345kV line interconnections.

For geomagnetic storms, the orientation of specific transmission lines becomes very important in determining their coupling to the geo-electric field which also has a specific orientation. For example if the orientation of a specific line is identical to the orientation of the geo-electric field, then the GIC will be at a relative maximum. Conversely if the orientations of the field and line are orthogonal, then no coupling or GIC flow will occur. In the case of the Chester to Keswick line, the orientation is at an angle of ~70^{o} (with 0^{o} being North) and for the Chester to Orrington line the angle is ~205^{o}. Hence it should be expected that each line will couple differently as the orientation of the geo-electric field changes. Also an important parameter in the calculation of GIC is the line length which also describes the total resistance of this element of the GIC circuit. The point to point distances from Chester are ~80 km to Orrington and ~146 km to Keswick. Figure 9 provides the results of a simple single circuit calculation of the Chester transformer GIC connected to a 345kV transmission line of variable length with a transformer termination at the remote end of that line, the estimated GIC is also shown for the 80 km Orrington line and the 146 km Keswick line using a uniform 1 V/km geo-electric field strength. As shown in this figure, for the two line lengths only a small change in GIC occurs (~11%), even though there is nearly a factor of two difference in line lengths. This calculation assumes a full coupling with the orientation of the geo-electric field, as the geo-electric field changes its orientation to the line with time, and the GIC will change as prescribed via a sine function.

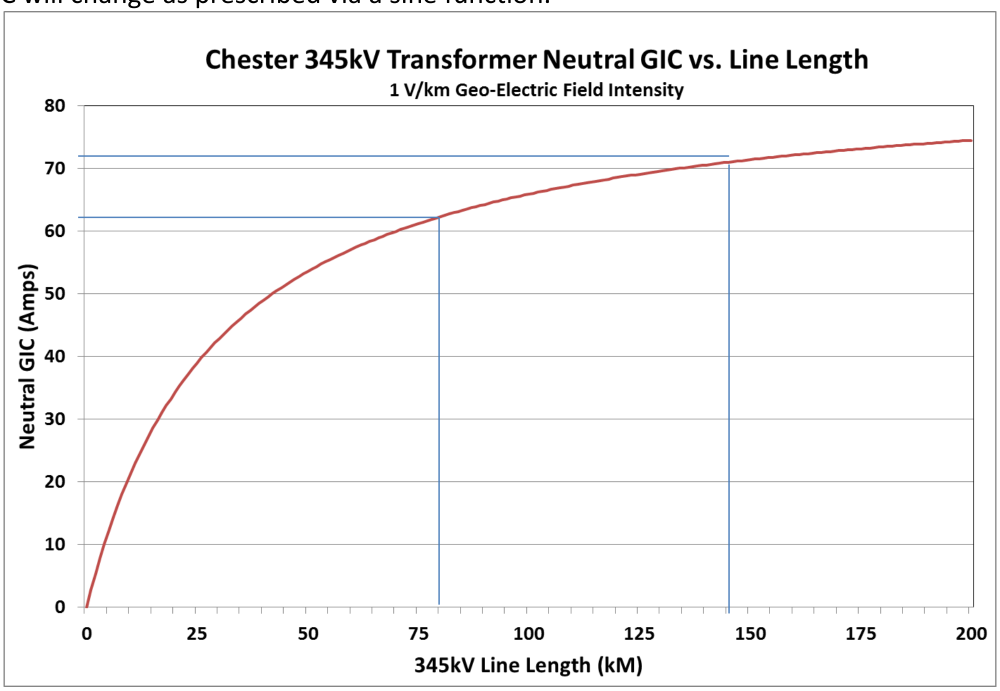

Figure 9 – Calculated Chester GIC for single circuit 345kV transmission line, 80 km Orrington and 146km Keswick noted

Given this simple two line case, a discrete calculation can be performed for each line, and using circuit superposition principles(Kirchoff's Laws), the resulting Chester GIC flow can be plotted as well versus the orientation angle of a uniform 1 V/km geo-electric field. This is shown in Figure 10 for each of the two lines and the resultant GIC flow at Chester.

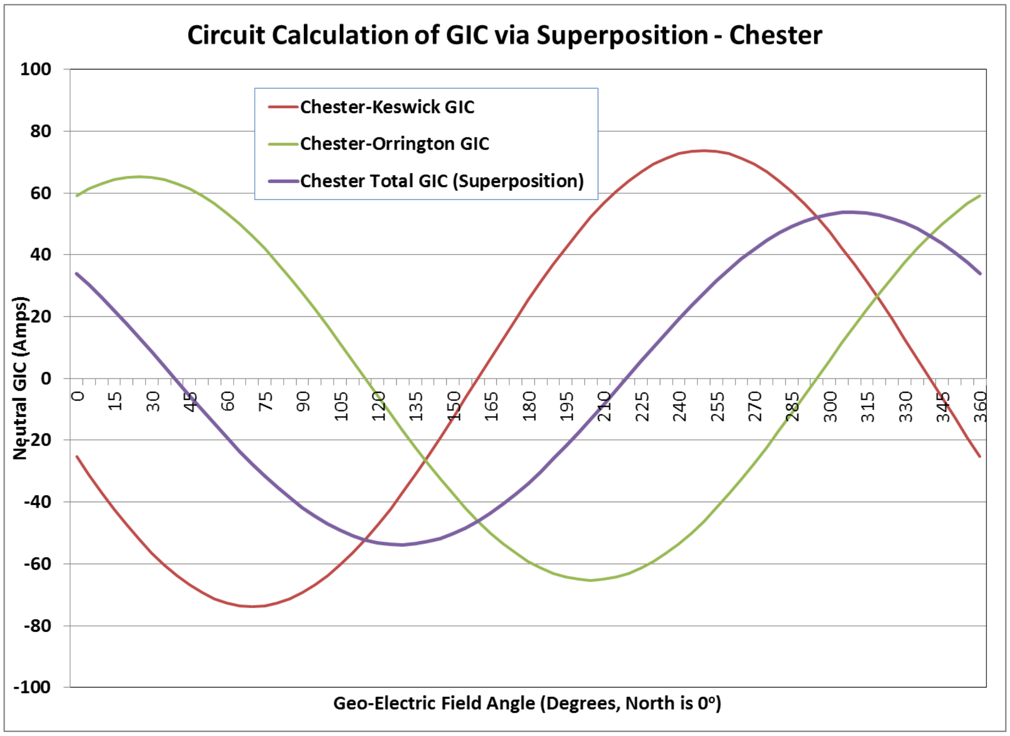

Figure 10 – GIC flow for each line versus geo-electric field angle and Resultant GIC at Chester.

Determining Storm Geo-Electric Field Intensity from Observed GIC

As this Figure 10 illustrates, each line segment will have differing GIC flows versus the orientation of the geo-electric field, and the resultant Chester neutral GIC will also be of lower magnitude and will also have a differing vector angle to each line segment. This simple Ohm's law based circuit calculation can be compared to the more detailed model calculation previously shown in Figure 7, which is shown in Figure 11. As this Figure illustrates, there is very good agreement in GIC flows using the two-line calculation approache (~95% agreement). The detailed model result will be more exact because all of the other network assets are used in the calculation. However, this comparison also shows that the line length parameter dominates the impedance of the circuit and defines the circuit current given the circuit resistances of just a few key components. Knowing both I (or GIC in this case) and R of the circuit allows the ability to precisely determine the driving V or geo-electric field that caused the observed GIC to occur in the transformer.

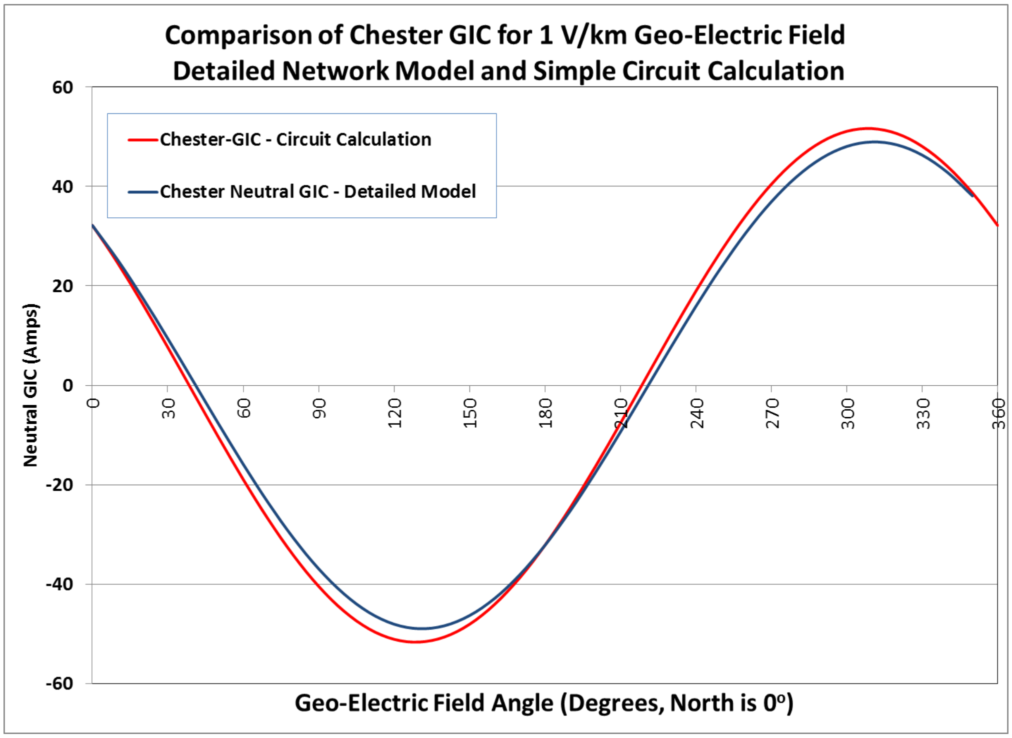

Figure 11 – Comparison of Calculated Chester GIC from detailed model and simple circuit calculation

Using the data from Figures 6 (the observed GIC at Chester) and Figure 11, it can be immediately inferred that the peak GIC levels of -66.6 and -74.3 Amps would have required a geo-electric field intensity of greater than 1 V/km to have occurred to produce such high levels of GIC. This is simply a process of utilizing Ohm's law knowledge to begin to develop an improved understanding of the geo-electric field intensity, an otherwise complex and uncertain field to calculate. In contrast it is not possible to infer the upper bound of geo-electric field, in that at angles where GIC nulls occur (such as 40^o and 220^o) even with a very high geo-electric field will not produce a significant GIC flow. As this point illustrates, these estimates can also be greatly improved by adding a simple understanding of geometry to this calculation. For example at time 4:16 UT, the simulation model results shown previously in Figure 3 illustrates a geo-electric field orientation at the Chester location which is almost exactly at 130^o, the orientation that would produce a peak GIC response at Chester. Using this circuit relationship of current to voltage allows extension to a scaling of the 49 Amp GIC at 1 V/km to a field intensity that would instead result in a 74.3 Amps GIC magnitude. This would lead to the estimated geo-electric field intensity at this 4:16UT time of ~1.5 V/km.

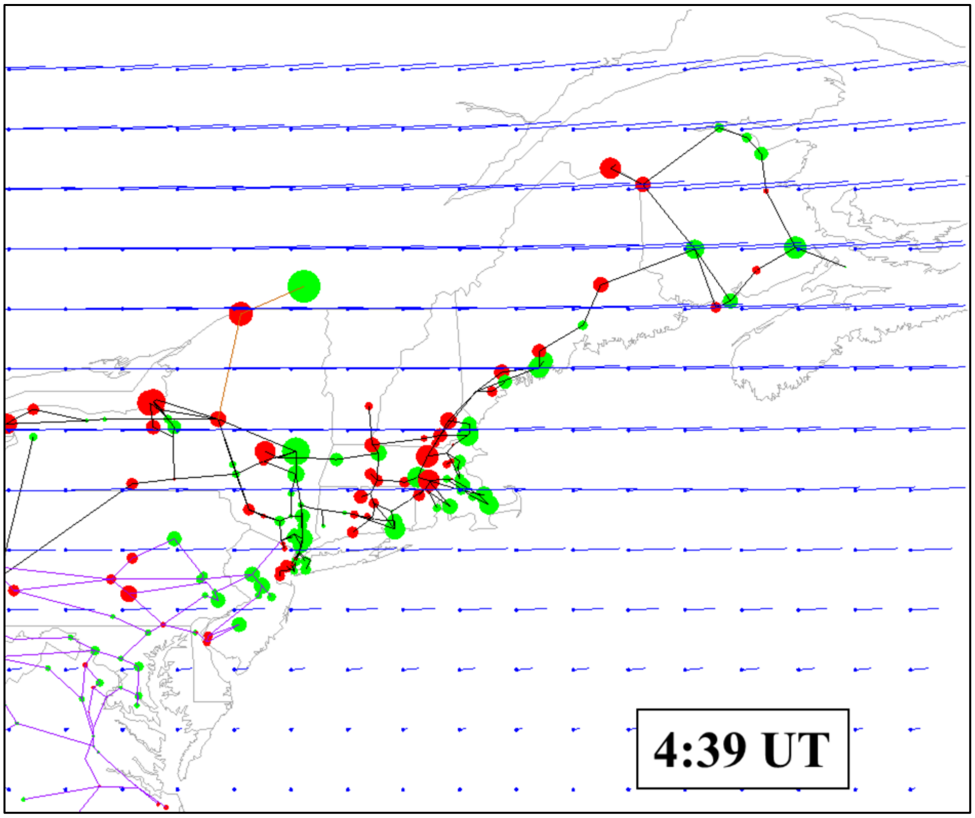

Figure 12 - GIC flows and disturbance conditions in Maine/New England grid at 4:39UT, May 4, 1998.

A similar simplified empirical analysis to confirm model results and expected geo-electric field levels can also be performed at time 4:39UT. Figure 12 provides a simulation output at time 4:39UT which again shows the intensity and geo-electric field angular orientation that would have occurred at this time step. This shows that the field was Eastward oriented or ~90°. Since the characteristic GIC flows at Chester behave as a sine wave for variation of the geo-electric field angle to these circuit assets, a scaling factor based on these angular characteristics can also be applied, which would rerate the field to account for the less-optimal orientation angle at this time. In this case, the 66.6 Amp GIC would be produced by total geo-electric field of ~2 V/km, but only ~1.4 V/km of this total geo-electric field is utilized to produce a GIC flow in the Chester transformer. As this case illustrates, a higher total geo-electric field intensity occurred at 4:39UT than at time 4:16 UT, even though the GIC is lower at 4:39UT. This appears to be counter intuitive. However the event produced a smaller GIC, with the important difference being the angular orientation of the field alone.

As this example illustrates, the observation of GIC when properly placed in context provides an ability to develop an important metric for calculation of the driving geo-electric field that caused the GIC.

Validating the NERC Geo-Electric Field for Ottawa and New England Ground Models

As the previous discussion has revealed, the knowledge of GIC flows combined with the network resistance characteristics and locations of network assets can provide all of the information needed to fully resolve the storm Geo-Electric Field Intensity at any particular time during the storm. In other words knowing I and R allows the application of Ohm's law and geometry to derive V or the Geo-Electric Field. This means that GIC measurements can be utilized to derive the geo-electric field at all observation locations and provide important validations of the NERC Ground Models and Geo-Electric Field calculation methodology.

To better understand how GIC can be used to validate the NERC geo-electric field calculations, the regional nature and footprint of each storm needs to be more fully explained. Figure 13 provides a map of the Ottawa and St John's geomagnetic observatories and their proximity to the Chester substation in Maine. As this map illustrates, Chester is positioned in between these two observatories with Ottawa being ~550 km west of Chester and St. Johns being ~1230 km to the east of Chester.

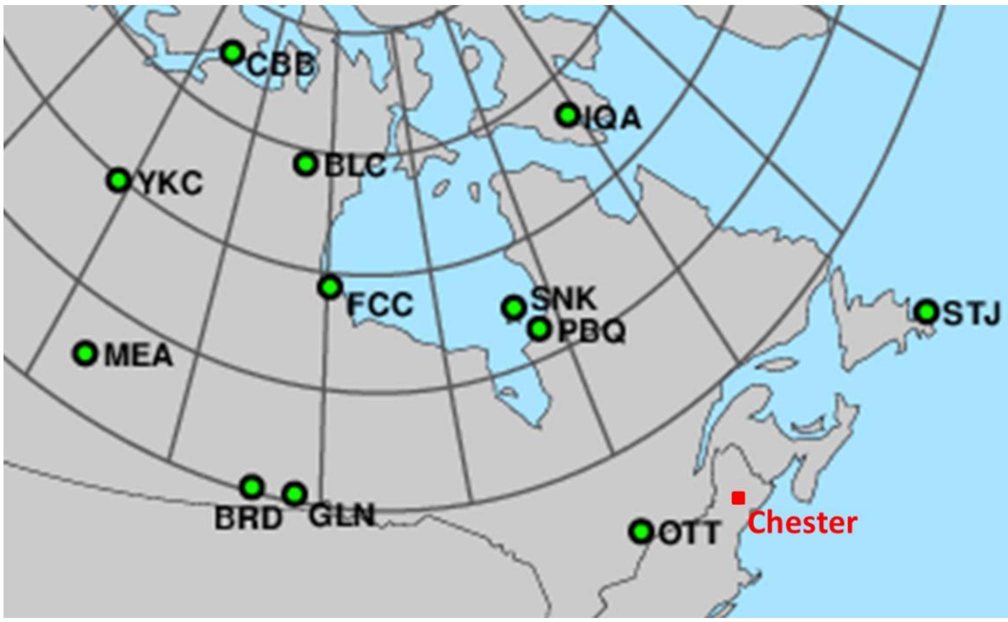

Figure 13 – Map showing Locations of Chester substation in comparison with Ottawa and St. Johns geomagnetic observatories

During the time period around 4:39UT which resulted in the peak GIC flow at Chester, both the Ottawa and St. John's geomagnetic observatory also recorded similar impulsive disturbance levels. This plot of these two observatories is shown in Figure 14. Because both of these observatories recorded this same coherent impulsive disturbance, this suggests that the observations had to be connected to the same coherent ionospheric electrojet current structure (in this case an intensification of the Westward Electojet Current) that would have extended all the way between these observatories and directly in proximity to Chester, Maine as well.

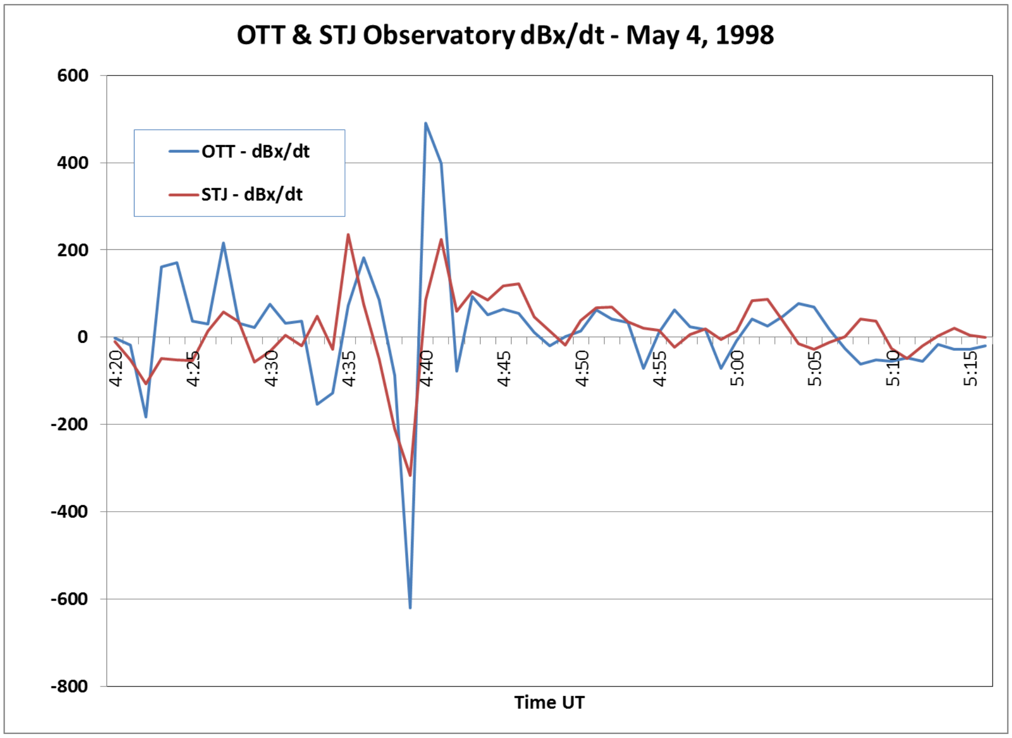

Figure 14 – Observed Impulsive disturbance at Ottawa and St. John's on May 4, 1998 at time 4:39UT.

At Chester some limited 10 second cadence magnetometer data was also observed during this storm, and Figure 15 provides a plot of the delta Bx at Ottawa (1 minute data) compared with the Chester delta Bx (10 sec) during the electrojet intensification at time 4:39UT. As this comparison illustrates that at this critical time in the storm, the disturbances at both Ottawa and Chester were nearly identical in intensity.

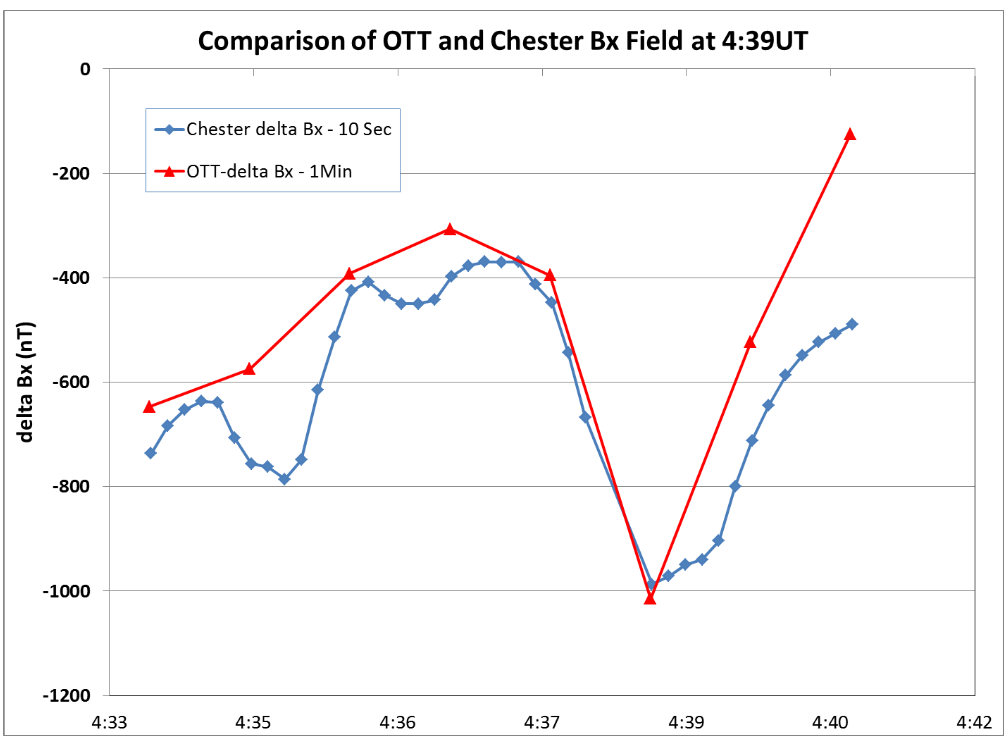

Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.

This close agreement between the observations at Ottawa and at Chester therefore allows the comparison of geo-electric field estimates between these two sites to be compared. As we had previously established using Ohm's Law, the peak geo-electric field must reach ~2 V/km to create the level of GIC observed during this storm. Geo-electric field calculations using a simulation model developed by the NERC GMD Task Force can be compared with the simulated geo-electric field in the Metatech simulation[4]. This comparison is shown in Figure 16. In addition, several portions of this geo-electric field waveform comparison are noted.

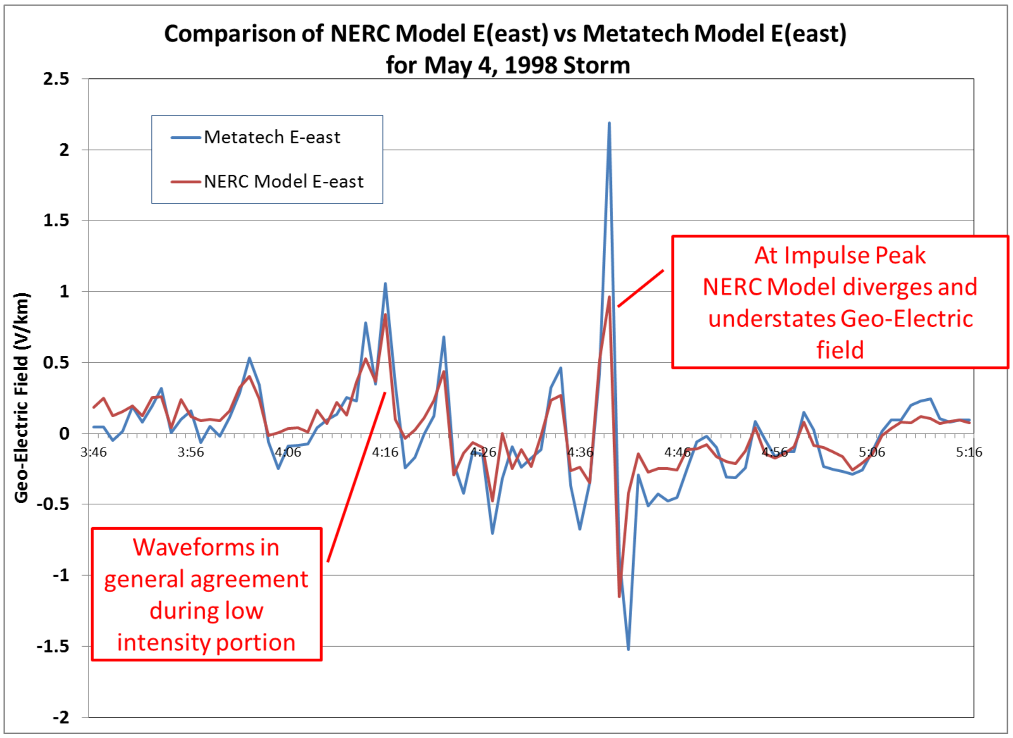

Figure 16 – Comparison of Metatech east-west geo-electric field calculation and NERC east-west geo-electric field calculation for May 4, 1998 storm event.

In the earlier portions of the storm simulation, the relative agreement between the two models for the geo-electric field is quite close. This occurs during a quieter and less intense portion of the storm. However as shown at the large impulse around time 4:39 UT, there is a divergence of agreement between the two models with the NERC modeling method understating the Metatech model results by a significant margin. After that impulse is over, the two models again come into relatively close agreement again. This suggests a problem in the NERC model of understating the intensity for more intense impulsive disturbances. As previously shown, the intensity in dB/dt is ~600 nT/min at time 4:39 UT, while it is generally below 100 to 200 nT/min at all other times during the simulation. Hence this higher intensity may be an important inflexion threshold within the NERC model.

As previously discussed Ohm's Law requires a sufficiently large enough geo-electric field to create the GIC flow observed at this location. Using the NERC model geo-electric fields it is possible to calculate the GIC flow and compare this to the GIC flow calculated for the Metatech model and even to the observed GIC. Figure 17 provides a comparison of the NERC model GIC with that computed in the

[4] Geo-elctric field data for this storm downloaded from NRCan http://www.spaceweather.gc.ca/data-donnee/dl/dl-eng.php#view

Metatech model. Figure 18 compares the same NERC Model GIC result with actual GIC observed at Chester. As both of these figures illustrate, the NERC model results will under predict the GIC at the peak storm intensities. In the case of the peak at time 4:39UT the understatement was similar in both the model comparisons and the observed GIC comparison.

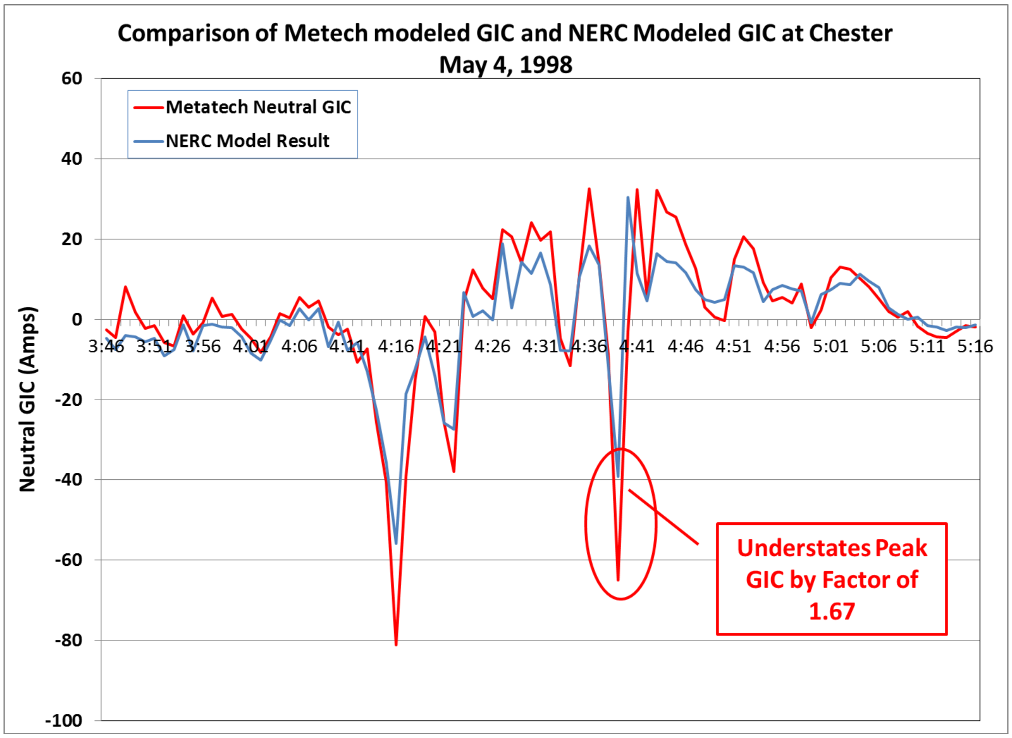

Figure 17 – Comparison of Metatech model GIC to NERC model GIC at Chester.

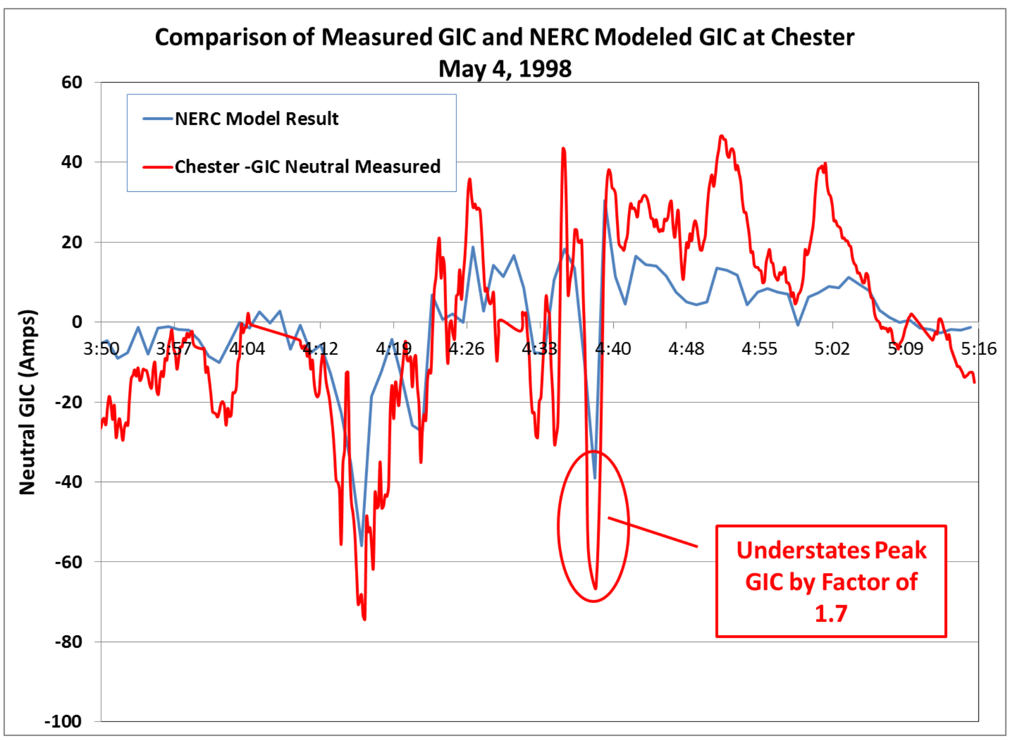

Figure 18 - Comparison of NERC model GIC to observed GIC at Chester.

NERC Model Validation Problems and Other GIC Observations

Seabrook GIC Observations July 13-16, 2012

While a number of GIC observations have been made over the last few decades in the US, very little of this information has been made publicly available. However where there is public information, it is possible to examine that data in a similar manner to the observations in Chester. Last year, observations as provided in Figure 19 were reported for GIC observations at the Seabrook Nuclear Plant[5]. These observations indicated peak GIC intensities during this storm that reached levels of 30 to 40 amps several times during the storm. The peak of 40 Amps occurred on July 16, 2012.

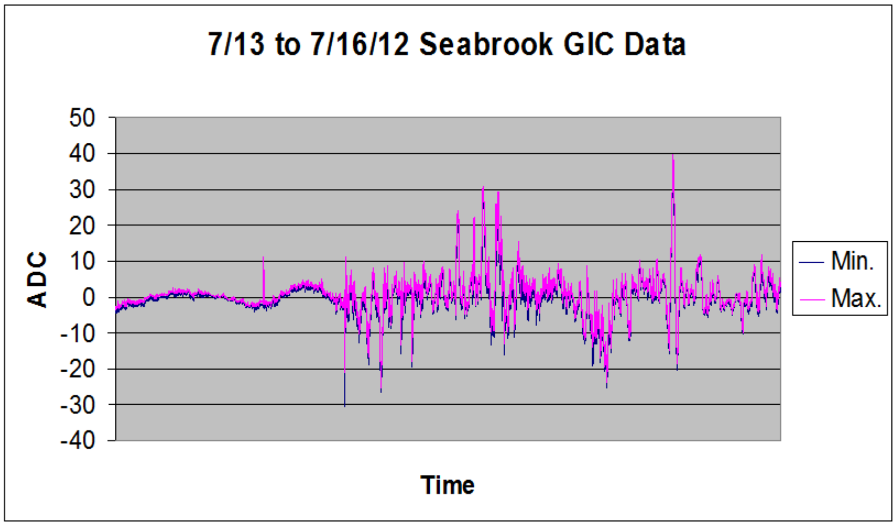

Figure 19 – GIC Observations at Seabrook Nuclear Plant July 13-16, 2012

Seabrook is also located in the New England region and because it is a GSU transformer, the neutral GIC also determines the flow that injects into the 345kV transmission network in that region. Figure 20 provides a map showing the location of Seabrook, and like Chester it will be heavily influenced by the same storm processes that will be observed at the nearby Ottawa observatory. In fact Seabrook is even closer to Ottawa than Chester.

[5] Geomagnetic Disturbance Mitigation for Nuclear Generator Main Power Transformers, Kenneth R. Fleischer, Presented April 16, 20132 at NOAA Space Weather Week Conference, Boulder Co.

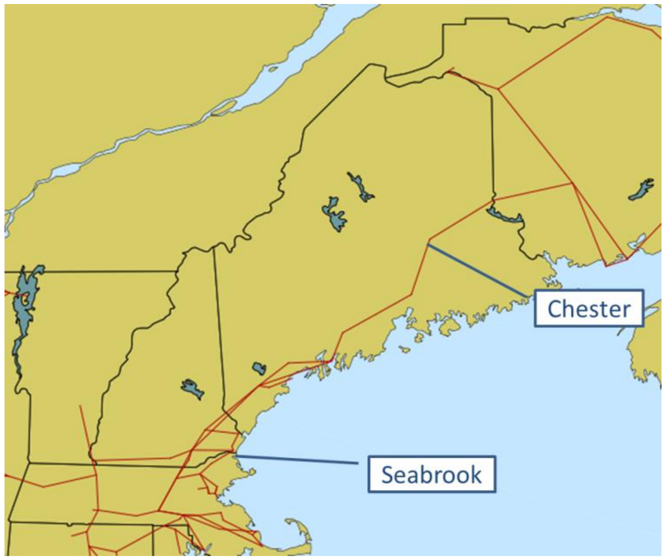

Figure 20 – Location of Seabrook Nuclear Plant in New England region 345kV network.

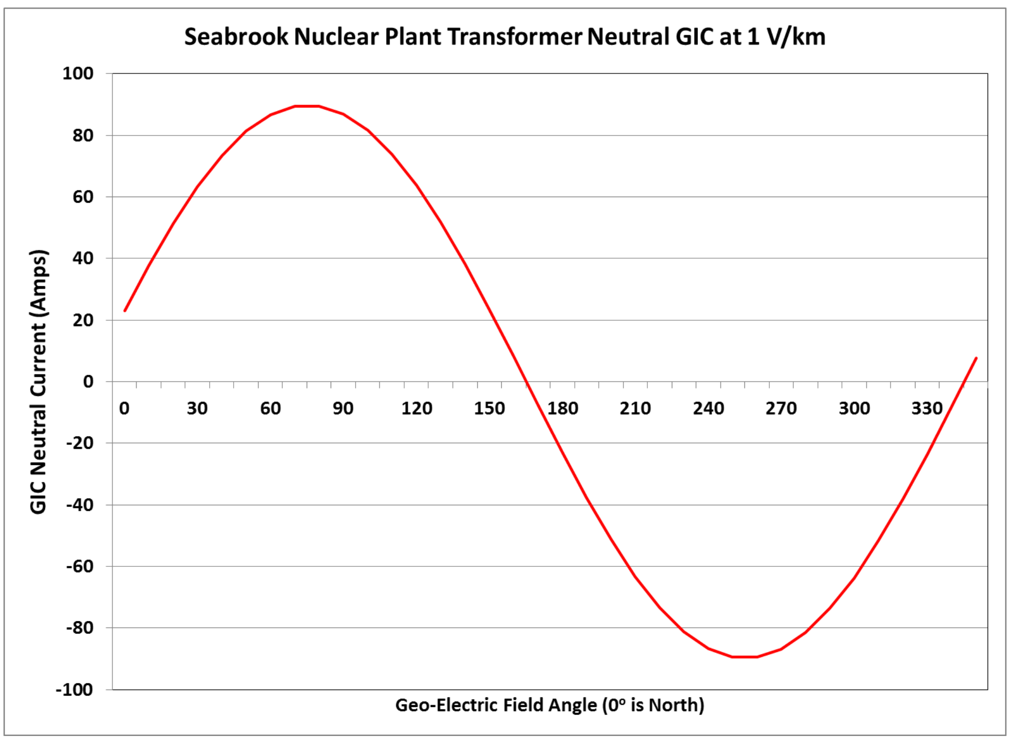

Figure 21 - GIC flow at Seabrook transformer neutral for 1 V/km geo-electric field at various orientation angles.

Figure 21 provides a plot of the characteristic GIC flows that would be observed at Seabrook for a uniform 1 V/km geo-electric field for a 360 degree rotation. This is computed similar to the way it was done at Chester. At this location, a 1 V/km geo-electric field produces ~90 Amp GIC at an 80^{o} angle (essentially nearly east-west oriented). Compared to the characteristic GIC plot for Chester (Figures 7 and 11), for a 1 V/km geo-electric field at Seabrook the GIC will be ~50% higher. This is due to the more integrated connections at Seabrook into the New England 345kV grid and lower circuit impedances, as would be expected. This characteristic indicates that for the 40 Amp GIC observation that occurred on July 16, 2012, there must have been a net east-west geo-electric field of ~0.45 V/km to produce this large of a GIC, a requirement dictated by the Ohm's law behavior of the circuit at Seabrook.

Figure 22 provides a plot of the East-West Geo-Electric Field that would be derived using the NERC model from this storm, using the Ottawa observatory geomagnetic field disturbance conditions as the input. As shown the peak field intensity reaches only ~0.1 V/km which is ~4 times too low to produce the actual GIC observed at Seabrook for this storm event. Hence this storm simulation model provides an example of even worse GIC validation attempt than at Chester. (Not shown is that the peak north-south geo-electric field would have been ~0.12 V/km. But these are also too low and would not couple efficiently with the Seabrook region circuits; therefore this was not a factor in the GIC levels at Seabrook.)

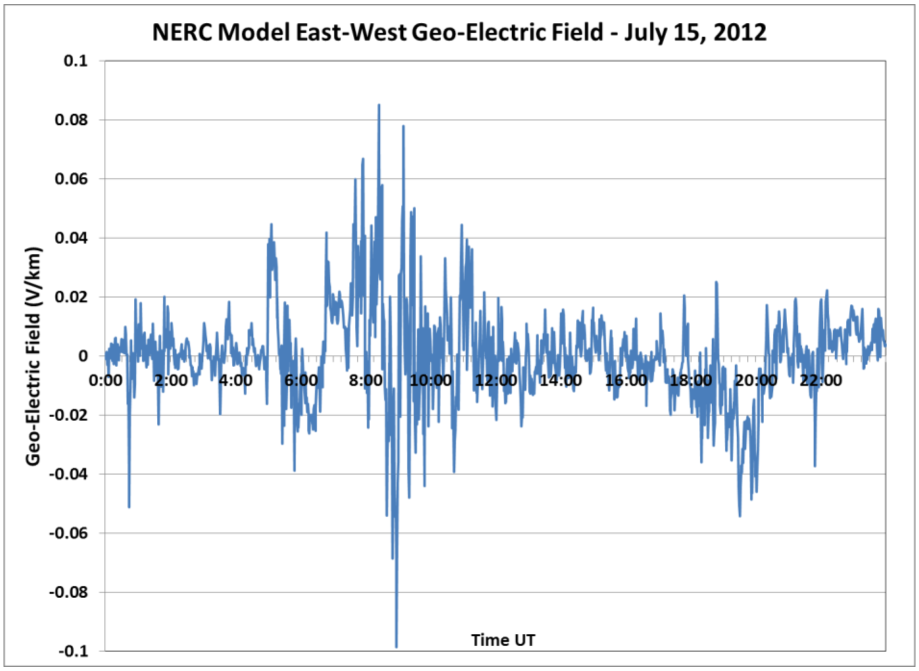

Figure 22 – NERC Model estimated East-West Geo-Electric Field on July 15, 2012 for the NE1 ground model.

BPA Tillamook GIC Observations Oct 30, 2003

In another situation, an examination has been conducted for ground models in the Pacific northwest region of the US. Data on GIC observations in the BPA transmission system have been provided to the Resilient Society Foundation under FOIA provisions and have been provided for analysis and ground model validation purposes. The GIC observations at the BPA Tillamook 230kV substation are examined in this case study. The Tillamook substation is on the western end of the BPA transmission network as shown in the map in Figure 23. There is a single 230kV line from Tillamook to the Carlton substation, but also 3 115kV lines that also connect at Tillamook, two which go in mostly North-South directions and one that connects to the East at Keeler.

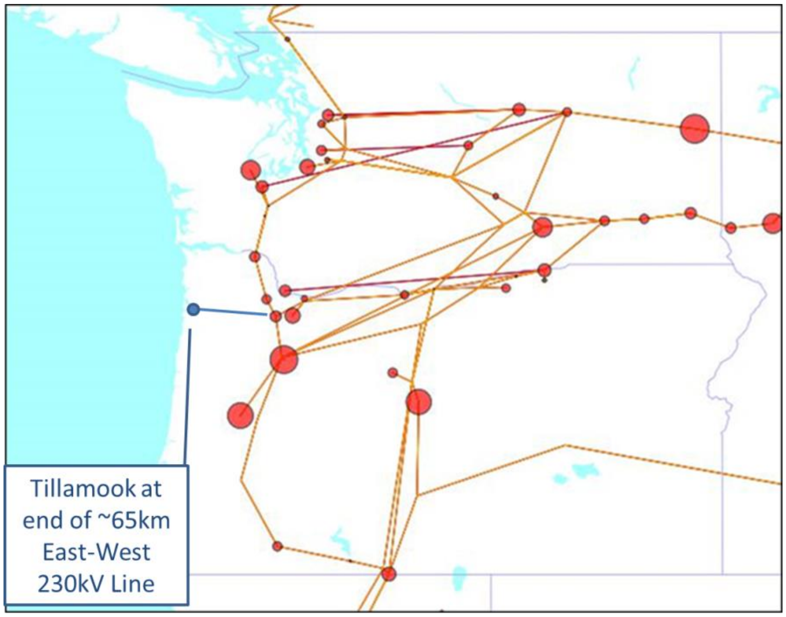

Figure 23 – Map of Tillamook 230kV substation and BPA 500kV network

Figure 24 provides a set of observations of GIC over a 2 hour time period at Tillamook which BPA provided in both 5 minute average and 2 second cadences during the October 30, 2003 storm. As shown in the 2 sec cadence data, the peak GIC approached nearly 50 Amps around time 19:55UT.

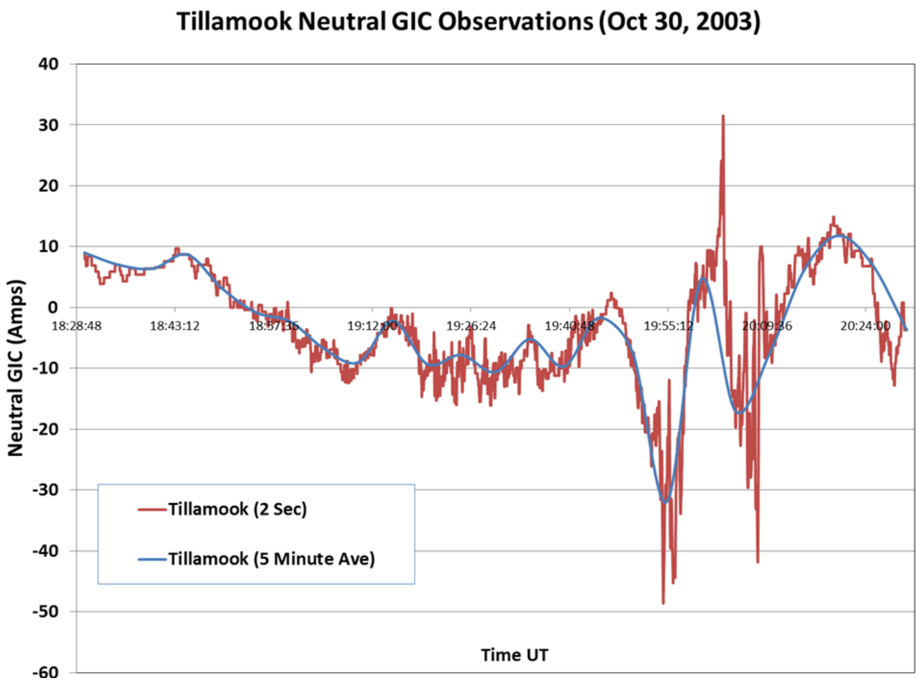

Figure 24 – Tillamook Neutral GIC observations on Oct 30, 2003, both 2 second and 5 minute average levels are shown

The Oct 30, 2003 storm conditions around time 19:55 UT are summarized from regional geomagnetic observatories as shown in Figure 25. This summary indicates that a region of intensification did encroach down into the Tillamook proximity at this time and would have been responsible for the peak GIC flows observed at this time, though Tillamook was not exposed to the worst case storm intensities.

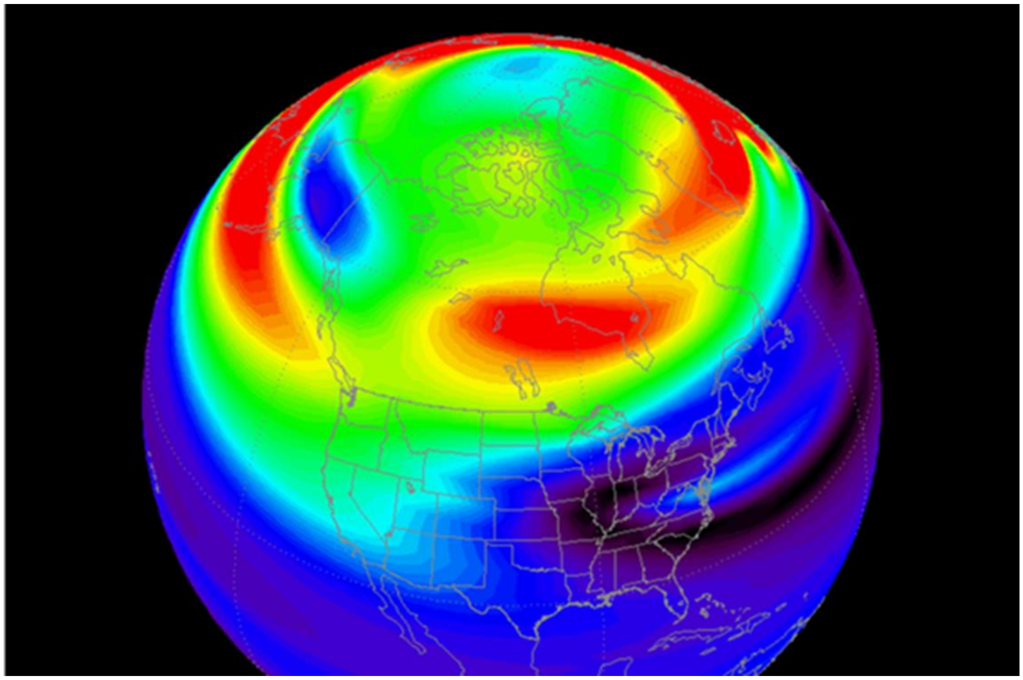

Figure 25 – Regional storm conditions at time 19:55UT October 30, 2003 at time of peak Tillamook GIC flows

Using methods similar to those developed for the Chester station and the various BPA physical data sources available, the characteristic GIC flows for the Tillamook 230kV autotransformer can be calculated for a rotated 1 V/km geo-electric field. The results for this are shown in Figure 26 and the peak GIC reaches a level of ~38 Amps for a predominantly east-west oriented geo-electric field. Therefore when examining the GIC levels observed at Tillamook on Oct 30, 2003, Ohm's law would constrain that the minimum geo-electric field in this region would need to exceed 1 V/km (in at least the east-west direction) to produce the nearly 50 Amps GIC peaks.

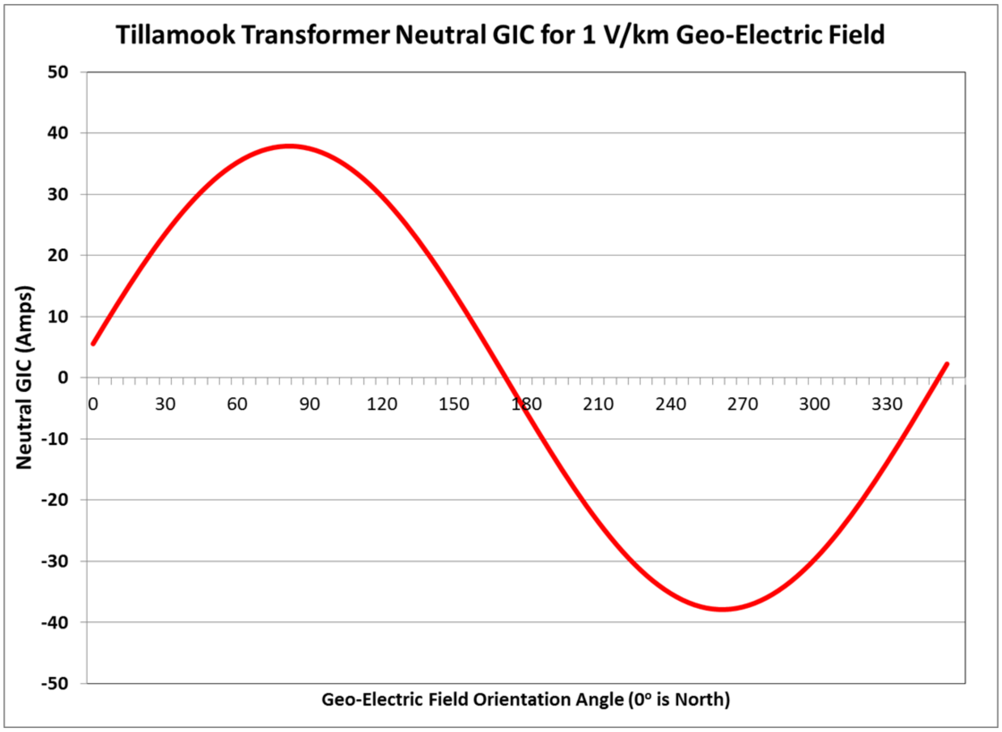

Figure 26 - GIC flow at Tillamook transformer neutral for 1 V/km geo-electric field at various orientation angles.

The NERC model calculations for East-West geo-electric field using the PB1 model are shown in Figure 27 for the same time interval as shown in Figure 24 for the Tillamook high GIC observations, but since the Tillamook GIC flow characteristics are defined in Figure 26, it is possible to utilize this to derive the minimum East-West geo-electric field responsible for producing the GIC flows in Figure 24. These results are also presented in Figure 27 with the NERC model predictions for this storm.

As Figure 27 shows, the peak geo-electric field as strictly constrained by Ohm's law must exceed 1 V/km during portions of the GIC flow where the Tillamook GIC exceeded ~38 amps level. At all times, the NERC model geo-electric field did not exceed even 0.25 V/km. As this comparison illustrates, the NERC model greatly understates the peak geo-electric field intensities at the peak GIC flow portions of the storm. In some cases this understatement is more than a factor of 4 to 5 times too small. This degree of divergence is also worse than what was observed at Chester Maine and is similar to the error level noted for Seabrook.

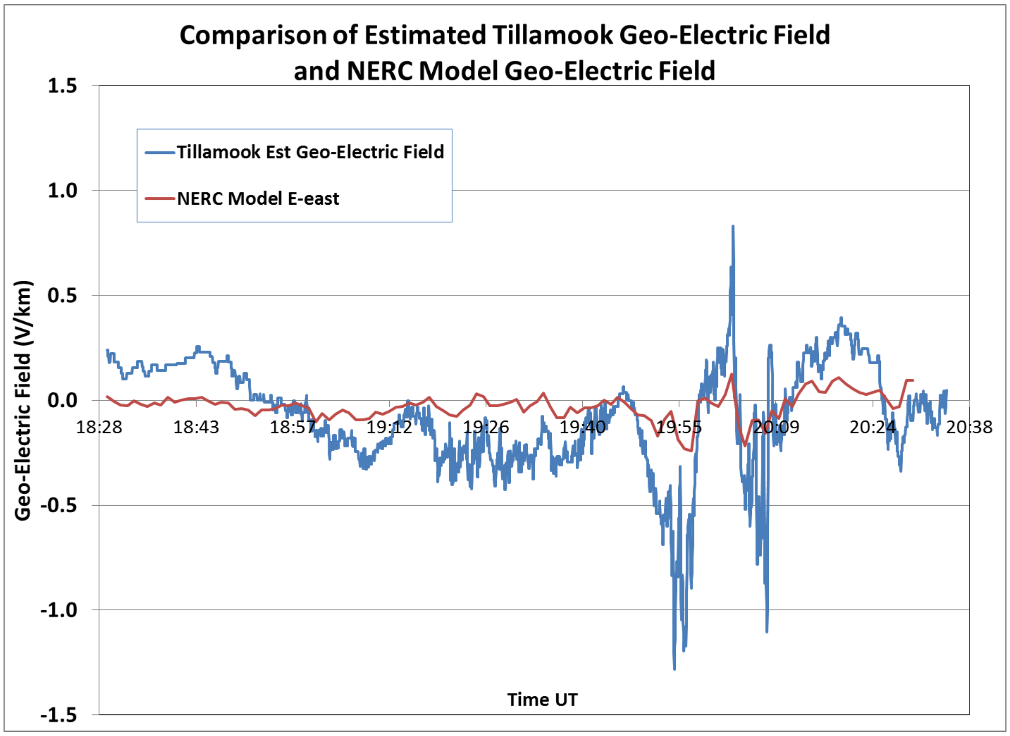

Figure 27 – Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the Oct 30, 2003 storm

There are other storms available with similar levels of GIC measurements observed at the Tillamook substation and 230kV line. Because this 230kV line is an East-West orientated line, GIC observed there will be largely driven by North-South variations (or dBx/dt) in the geo-magnetic field which subsequently produces an East-West geo-electric field. Figure 28 provides a plot of the nearest geomagnetic observatory (Victoria, ~340 km north of Tillamook) and the Tillamook GIC observed during an important storm on July 15-16, 2000. These geomagnetic disturbance conditions reach a peak of just over 150 nT/min resulting in GIC flows (5 min averaging) reaching -43.5 Amps at time 20:25UT. Figure 29 provides a detailed regional summary which show the more global storm conditions that were occurring at time 20:25UT over North America. As this Figure illustrates, the most severe storm conditions were located quite far to the North, so the GIC observed for these conditions could have been driven to much higher levels had the intensity extended further southward.

From the GIC observations for this storm, the minimal Geo-Electric field levels necessary to produce the GIC flows observed at Tillamook can be again calculated. This can also again be compared with the estimates used by NERC in modeling this storm event, this comparison is shown in Figure 30. In the comparison of the NERC model geo-electric field with the actual geo-electric field as derived from GIC measurements, the NERC model again greatly under predicts peak V/km intensities, by as much as a factor of ~5 or more at peak intensities times. These results are similar to the results from the Oct 30, 2003 storm as shown in Figure 27 and further confirm that the NERC models will not accurately depict storm conditions.

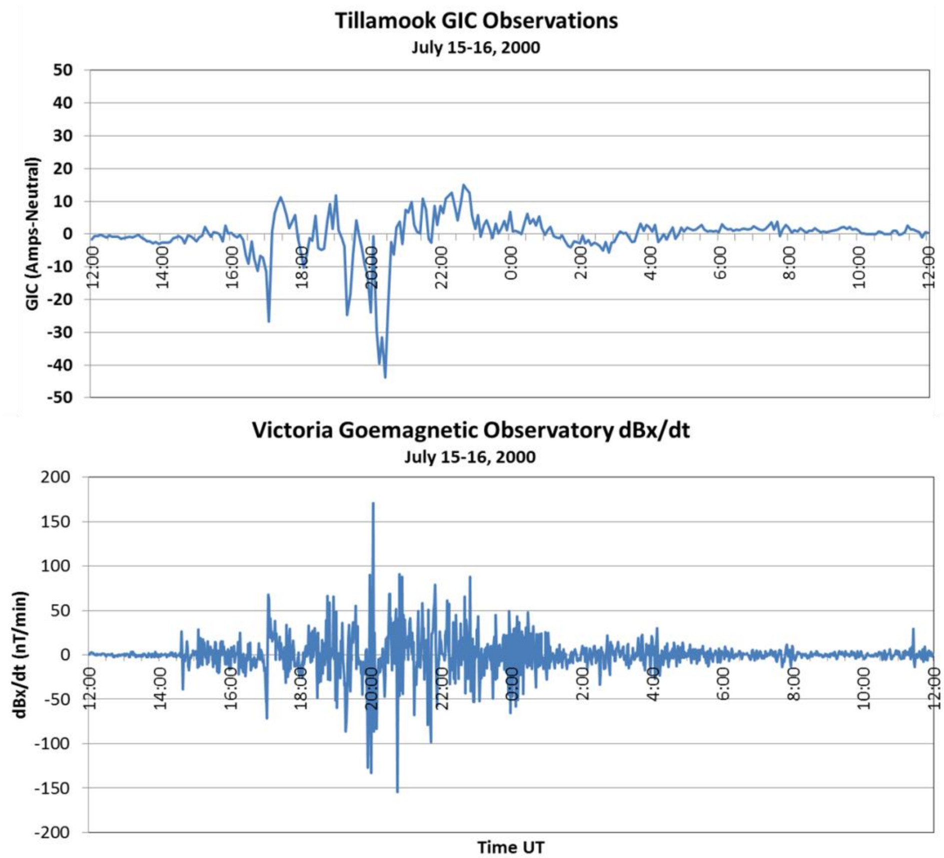

Figure 28 – Observed Tillamook GIC and Victoria dBx/dt for storm on July 15-16, 2000.

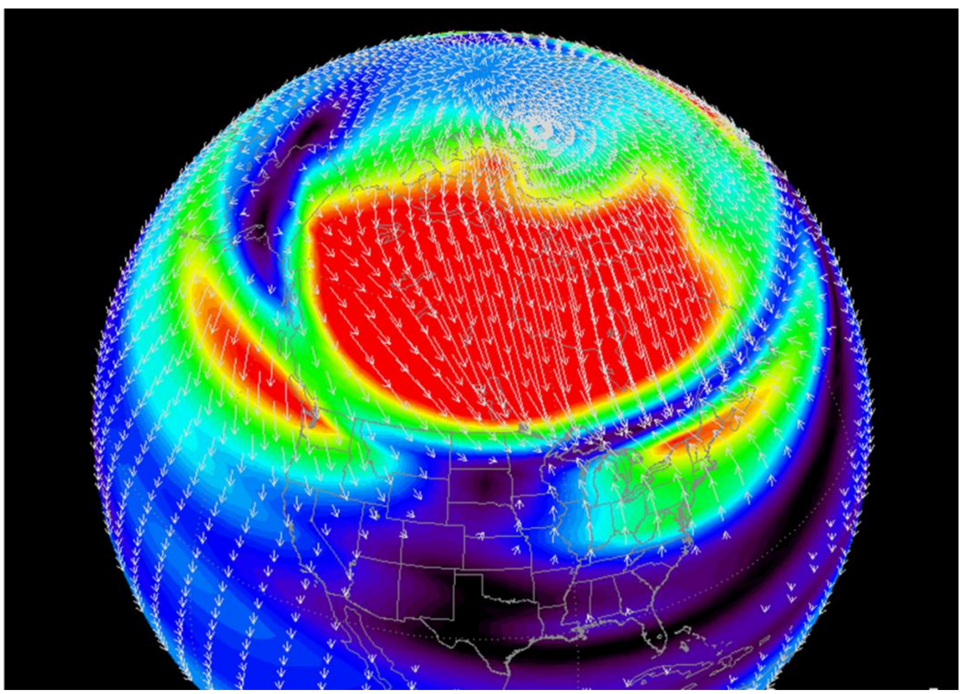

Figure 29 - July 15, 2000 at time 20:25UT storm conditions at time of Tillamook -43.5 Amp GIC Peak.

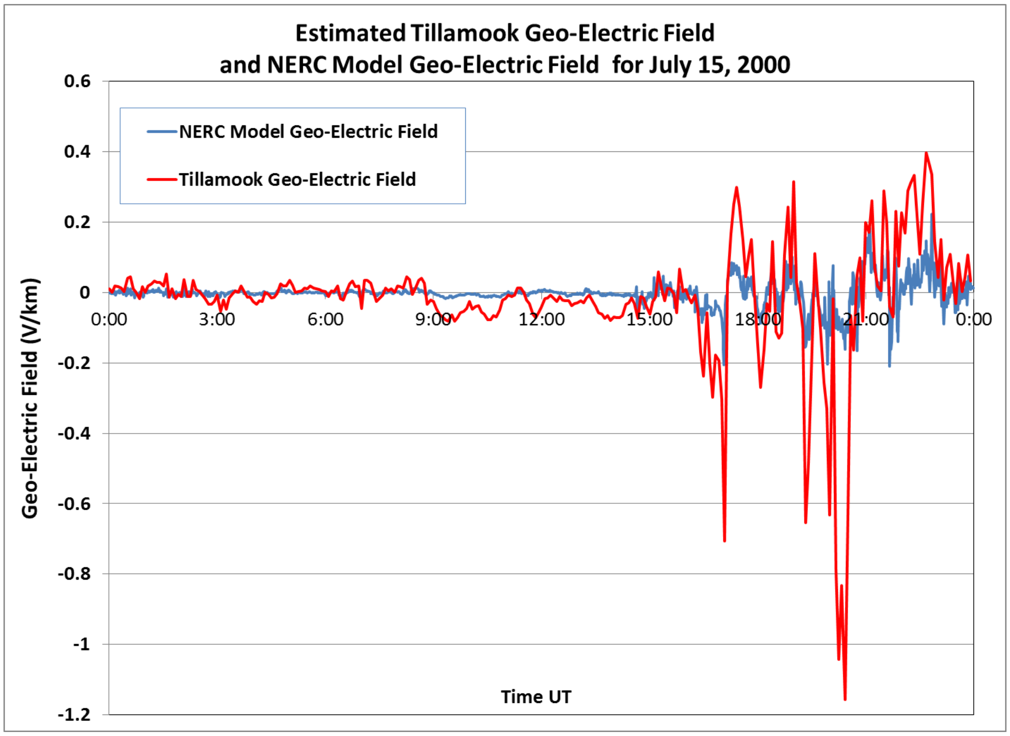

Figure 30 - Comparison of NERC Model geo-electric field with estimated geo-electric field needed to produce Tillamook GIC flows for the July 15, 2000 storm

Other Instances of Geo-Electric Field Modeling Concerns

The NERC geo-electric field simulation tools had their genesis out of the Finnish Meteorology Institute and have since been adopted at NASA (A. Pulkkinen) and also at Natural Resources Canada and many other locations around the world. Pulkkinen in particular was a key NERC GMD Task Force science investigator, a key EPRI science investigator along with staff from NRCan. Pulkkinen was also a member of the NERC GMD Standards Task Force, where the draft standards incorporating these tool sets are fully integrated into the science analysis and are recommended tools for system analysis. In the entirety of the NERC GMD task force investigations, no evidence has been made available by the NERC GMD Task Force of rigorous validations of the suite of ground models and derived relationships that have been published. USGS scientist involved in the effort asked for more power industry efforts to do model validations at several NERC GMD meetings, with no active participants and no subsequent publications supporting the ability to verify these models.

These FMI/NRCan-based geo-electric field modeling approaches use a Fourier transform method[6]. Fourier transforms are well-conditioned for periodic signals, not the very aperiodic events associated with abrupt, high intensity impulsive disturbances typical for severe geomagnetic storms. Therefore a Fourier approach needs to be carefully considered and tested rigorously to assure fidelity in output resolution for severe impulsive geomagnetic field disturbances. An additional geo-electric field modeling approach has been developed by Luis Marti based upon Recursive Convolution[7]. Unfortunately no independent validation for this model was noted in their IEEE paper on the model, rather it was only

[6] How to Calculate Electric Fields to Determine Geomagnetically-Induced Currents. EPRI, Palo Alto, CA: 2013. 3002002149.

[7] Calculation of Induced Electric Field During a Geomagnetic Storm Using Recursive Convolution, Luis Marti, A. Rezaei-Zare, and D. Boteler, IEEE TRANSACTIONS ON POWER DELIVERY, VOL. 29, NO. 2, APRIL 2014

tuned to agree with the FMI/NRCan geo-electric field model output results. In addition, staff from the NOAA SWPC and USGS were also provided tool sets that were tuned to the NASA-CCMC/NRCan geo-electric field models so that the results that each examined would be the same. Hence no real independent assessments were ever apparently undertaken by all of these organizations. Therefore all of the various NERC GMD models appear to produce results that will consistently understate the true geo-electric field intensity.

In looking at recent publications by Pulkkinen, et. al., a paper titled "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden"[8] was published in the Space Weather Journal in 2008. In this paper the authors presented results from several storm events that were similar in intensity to the May 4, 1998 storm that was discussed in a prior section of this report. Figure 31 is a set of plots from Figure 7 of their paper showing the disturbance intensity (dB/dt in nT/min) in the bottom plot and the measured and calculated GIC in the top plot. As illustrated in this Figure, the storm intensity is similar to that experienced in Maine during the May 4, 1998 storm at ~500 nT/min. In regards to the comparison of the Measured and Calculated GIC the simulation model greatly under predicts the actual measured GIC during the most intense portion of the storm around hour 23 UT by substantial margins (factor of 3 or more). This is the same symptomatic outcome observed in the NERC model results and provides another independent assessment with possible inherent problems with this modeling approach.

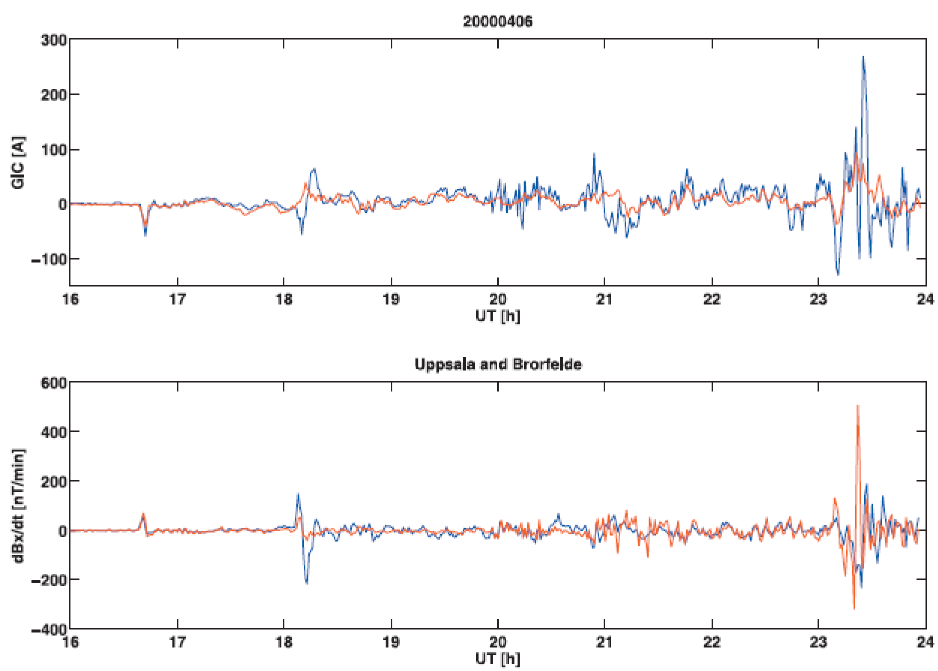

Figure 7. The top curve shows the measured (blue) and calculated (red) GIC at Simpevarp-2 (6 April 2000). The bottom curve shows dB_x/dt from Uppsala (blue) and Brorfelde (red).

Figure 31 – Plot Figure 7 from Pulkkinen, et.al.,paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing storm intensity and GIC comparisons

[8] Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden, M. Wik, A. Viljanen, R. Pirjola, A. Pulkkinen, P. Wintoft, and H. Lundstedt, SPACE WEATHER, VOL. 6, S07005, doi:10.1029/2007SW000343, 2008

In another example from this same paper, a figure shown below as Figure 32 provides a comparison plot of the Measured and Calculated GIC during the July 15, 2000 storm at the same transformer in southern Sweden. The GIC results as in all prior comparisons greatly diverge during the occurrence of the largest and most sudden impulsive disturbance events, such as those between 21 and 22 UT.

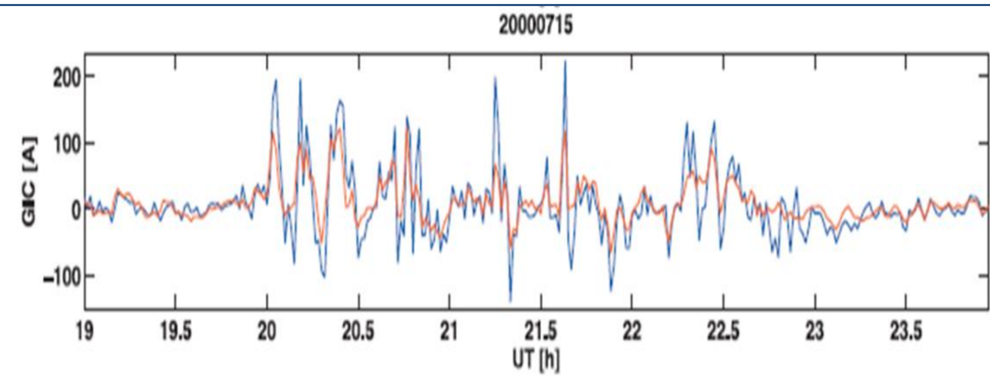

Figure 4. Measured (blue) and calculated (red) GIC at Simpevarp-2 for three events in 1998 to 2000.

Figure 32 - Plot Figure 4 from Pulkkinen, et.al.,Paper "Calculation of geomagnetically induced currents in the 400 kV power grid in southern Sweden" published 2008 showing GIC comparisons

Conclusions – Draft NERC Standards are Not Accurate and Greatly Understate Risks

As these examples illustrate the results of calculations of geo-electric fields by the NERC models and any subsequent NERC predicted GIC's appear to exhibit the same problems of significantly under predicting for intense storm disturbances. In all locations that were examined the results of the models consistently under predicted what Ohm's Law establishes as the actual geo-electric field. This is a systemic problem that is likely related to inherent modeling deficiencies, and exists in all models in the NERC GMD Task Force and likely in many other locations around the world.

This has significant implications for nearly all of the findings of the NERC GMD Task Force. These erroneous modeling approaches were utilized to examine the peak geo-electric field outputs to much higher disturbance intensities for severe storms. For example the underlying analysis performed by NERC Standard Task Force members Pulkkinen and Bernabeu[9] for the 100 Year storm peaks utilized the faulty geo-electric field calculation model to derive the peak geo-electric fields for the reference Quebec ground models. This would drastically understate the peak intensity of the storm events by the same factor of 2 to 5 ratios as noted in the prior case study analysis. Therefore the standard proposing the NERC Reference Field level of between 3 to 8 V/km would be an enormous under-estimation and result in an enormous miss-calculation of risks to society. The same modelling errors are part of all earlier Pulkkinen/Pirjola[10] derived science assessments which also examined these peaks and 100 year storm statistics. As all prior validations within this report have established, the NERC geo-electric field model under predicts geo-electric field by a factor of 2 to 5 for the most important portions of storm events. Hence these errors have been entirely baked into the NERC GMD Task Force cake and their draft standards as well. Therefore the entirety of the Draft Standard does not provide accurate assessments

[9] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

[10] Pulkkinen, A., R. Pirjola, and A. Viljanen, Statistics of extreme geomagnetically induced current events, Space Weather, 6, S07001, doi:10.1029/2008SW000388, 2008.

of the geo-electric field environments that will actually occur across the US. It has also been shown in this White Paper that undertaking a more rigorous development of validated geo-electric field standards can be done in a simple and efficient manner and that such data to drive these more rigorous findings already exists in many portions of the US. Efforts on the part of NERC's standard team and the industry to withhold this material information are counter-productive to the overarching requirements to assure public safety against severe geomagnetic storm events. Such fundamental and significant flaws in technical calculations and procedural actions should not be a part of any proposed standard and a redraft must be undertaken.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.

Description of Current Draft

This is the second draft of the proposed Reliability Standard. It is posted for 45-day comment and additional ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale:

Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, they are not included in the applicability for this standard.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes,

agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.

R2. Responsible entities as determined in Requirement R1 shall maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. A responsible entity as determined in Requirement R1 shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

R3. Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. A responsible entity as determined in Requirement R1 shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

R4. Responsible entities as determined in Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. Studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. A Responsible entity as determined in Requirement R1 shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Rationale for Requirement R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and supporting studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

R5. Responsible entities as determined in Requirement R1 shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer. The GIC flow information shall include for each applicable power transformer: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. Maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1; and

5.2. Effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 for each applicable power transformer where the maximum effective GIC value for the worst case geoelectric field orientation exceeds 15 A per phase.

M5. A responsible entity as determined in Requirement R1 shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC flow information to each Transmission Owner and Generator Owner that owns an applicable power transformer as specified in Requirement R5.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment.

The GIC flows provided in part 5.1 are used to screen the transformer fleet so that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

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:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for each of its solely and jointly owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its applicable solely and jointly owned power transformers where maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase and have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6:

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

R7. Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability Assessment conducted in Requirement R4 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.

- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. A responsible entity as determined in Requirement R1 that concludes through the GMD Vulnerability Assessment conducted in Requirement R4 that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R7. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity referenced in the Corrective Action Plan or to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R7. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments in accordance with Requirement R7.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α (2), β is applied to the reference geoelectric field using (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website[3]. The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

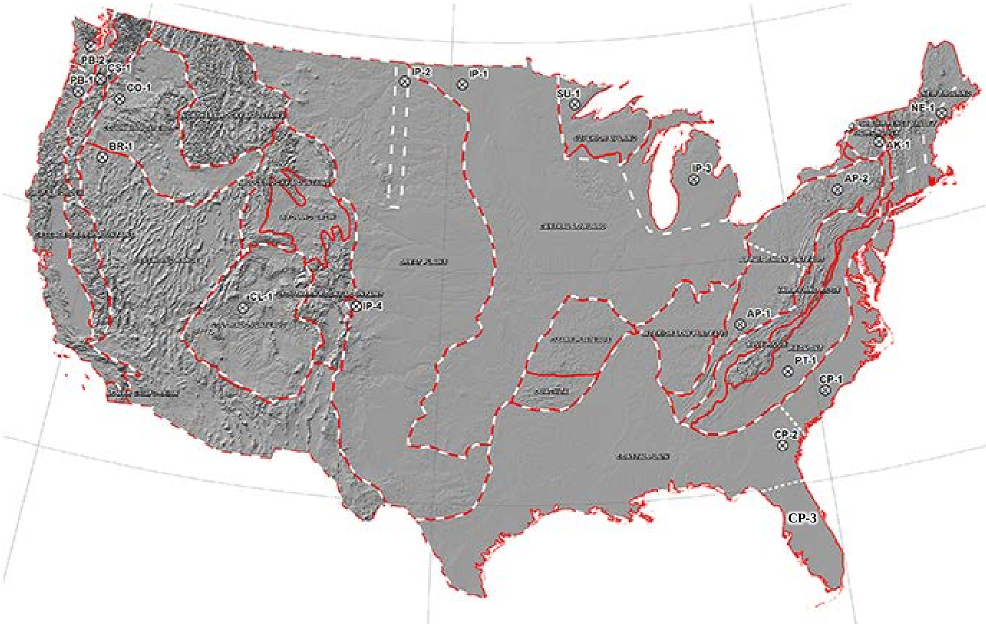

Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series where a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

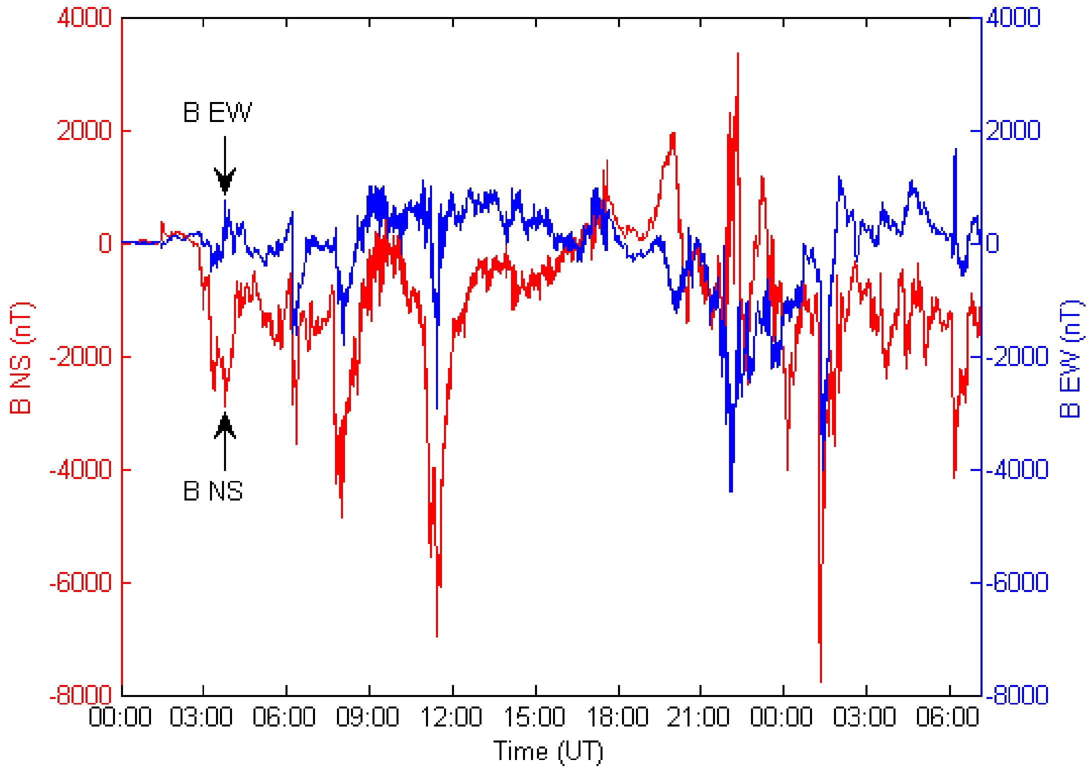

Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

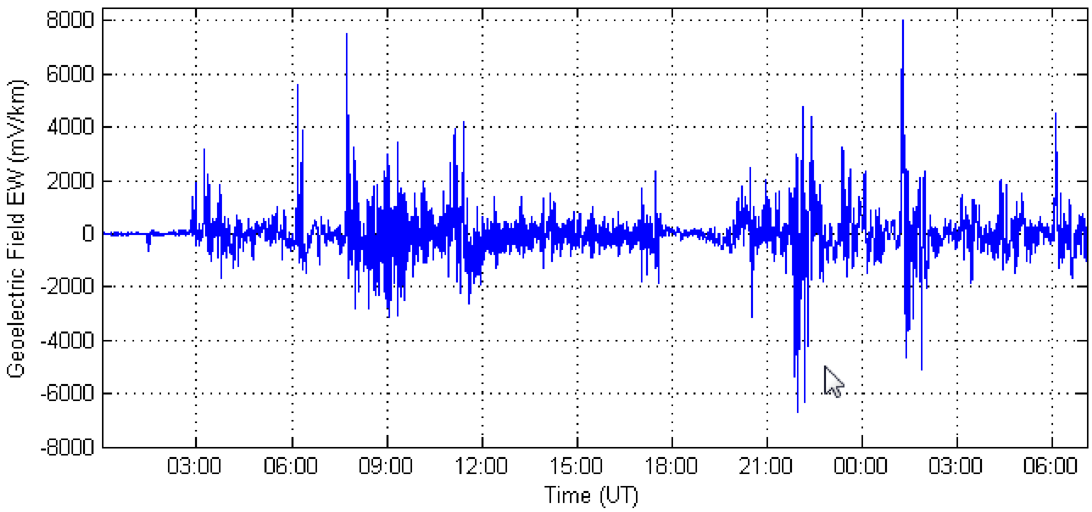


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

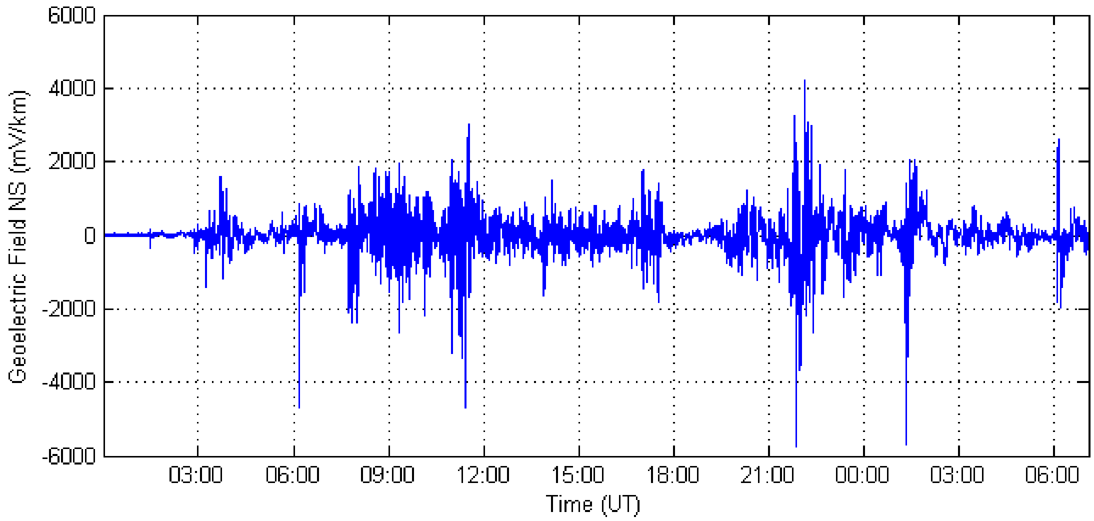


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	Medium	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

R5	Long-term Planning	Medium	N/A	N/A	The responsible entity failed to provide one of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.	The responsible entity failed to provide two of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer; OR The responsible entity did not provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.
R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1

			is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include two of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include three of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include four of the required elements as listed in Requirement R6 parts 6.1 through 6.4.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 parts 7.1 through 7.3; OR The responsible entity did not have a Corrective

						Action Plan as required by Requirement R7.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

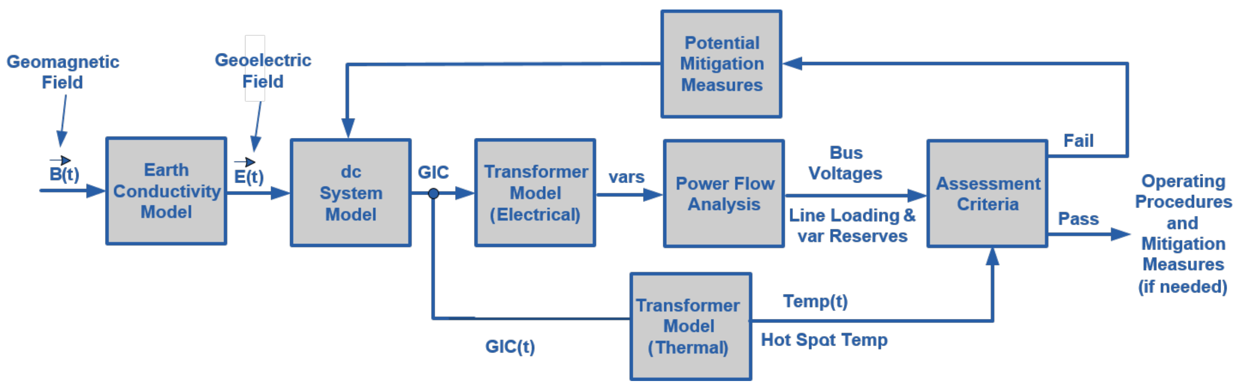
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC time series information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC system model and must be provided to the entity responsible for conducting the thermal impact assessment.

The maximum effective GIC value provided in part 5.1 is used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The effective GIC time series, GIC(t), provided in part 5.2 is used to conduct the transformer thermal impact assessment (see white paper for details).

The peak GIC value of 15 amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low. Additional information is in the following section.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2 is also a justifiable threshold criteria that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.

Description of Current Draft

This is the ~~first~~second draft of the proposed Reliability Standard. It is posted for 45-day comment and ~~initial~~ additional ballot.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Initial Ballot~~	~~June 2014~~
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

~~The definition shall become effective on the first day of the first calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~The Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Compliance shall be implemented over a 4-year period as described in the Implementation Plan.~~

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

> Rationale:
>
> Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, they are not included in the applicability for this standard.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes,

agreements, ~~and~~copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies ~~that~~ an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.

R2. Responsible entities as determined in Requirement R1 shall maintain System models and ~~geomagnetically-induced current (GIC)~~GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. ~~Responsible entities~~A responsible entity as determined in Requirement R1 shall have evidence in either electronic or hard copy format that it is maintaining System models and ~~geomagnetically-induced current (GIC)~~GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

R3. Responsible entities as determined in Requirement R1 shall have criteria for acceptable System steady state voltage ~~limits~~ performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. A responsible entity as determined in Requirement R1 shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage ~~limits~~ performance for its System in accordance with Requirement R3.

~~R3.~~R4. Responsible entities as determined in Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. Studies shall include the following conditions:

4.1.1. System ~~peak~~On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a ~~reliability related~~reliability-related need.

~~3~~4.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

~~M3.~~ M4. A Responsible enti~~ties~~y as determined in Requirement R1 shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement ~~R3. Responsible entities~~R4. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity who has ~~indicated~~submitted a written request and has a ~~reliability related~~reliability-related need as specified in Requirement ~~R3. Responsible entities~~R4. A responsible entity as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement ~~R3~~R4.

Rationale for Requirement ~~R3~~R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and supporting studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

~~**R4.**~~

R5. Responsible entities as determined in Requirement R1 shall provide ~~geomagnetically-induced current (~~GIC~~)~~ flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer. The GIC flow information shall include for each applicable power transformer: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. ~~5.1~~ Maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1; and

5.2. ~~5.2~~ Effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 for each applicable power transformer where the ~~M~~maximum effective GIC value for the worst case geoelectric field orientation exceeds 15 ~~Amperes~~A per phase.

M5. ~~Responsible entities~~A responsible entity as determined in Requirement R1 shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided ~~geomagnetically-induced current (GIC)~~GIC flow information to each Transmission Owner and Generator Owner that owns an applicable power transformer as specified in Requirement R5.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment.

The GIC flows provided in part 5.1 are used to screen the transformer fleet ~~such~~so that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The GIC flows provided by part 5.2 ~~and 5.3~~ 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: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for each of its solely and jointly owned applicable Bulk Electric System power transformers where the maximum effective ~~geomagnetically-induced current~~ ~~(~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase. The thermal impact assessment shall: *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5; ~~and~~

6.2. Document assumptions used in the analysis; ~~and~~

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities as determined in Requirement R1 within ~~12~~24 calendar months of receiving GIC flow information specified in Requirement R5.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its applicable solely and jointly owned power transformers where maximum effective ~~geomagnetically-induced current~~ ~~(~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase and have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6: The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the Transformer Thermal Impact Assessment white paper posted on the project page. http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

R7. Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability Assessment conducted in Requirement ~~R3~~R4 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, functional entities referenced in the Corrective Action Plan, and ~~to~~ any functional entity that submits a written request and has a ~~reliability related~~reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. ~~Responsible entities~~A responsible entity as determined in Requirement R1 that concludes through the GMD Vulnerability Assessment conducted in Requirement ~~R3~~R4 that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R7. ~~Responsible entities~~A responsible entity as determined in Requirement R1 shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity referenced in the Corrective Action Plan or to any functional entity who has ~~indicated~~submitted a written request and has a ~~reliability related~~reliability-related need as specified in Requirement R7. ~~Responsible entities~~A responsible entity as determined in Requirement R1 shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments in accordance with Requirement R7.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. ~~Load loss as well as generation~~Generation loss is acceptable as a consequence of the planning event.

~~c.~~ Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

~~d.~~c. ~~System steady state voltages shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner in accordance with Requirement R4.~~

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event[~~3~~]	Yes[~~4~~3]	Yes[~~4~~3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).

~~3. 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.~~

~~4.~~3. Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be ~~needed~~used to meet BES performance requirements during studied GMD conditions ~~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~~. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service ~~is~~should be minimized ~~during a GMD event~~.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute ~~geomagnetically-induced current (GIC)~~GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude ~~to be~~ used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \qquad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α ~~can be~~is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using 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~~; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak},~~ to be~~ used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor ~~α,~~α (2), β is applied to the reference geoelectric field using ~~the following equation~~(1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use ~~a~~the largest β factor of ~~1~~adjacent physiographic regions or a technically ~~-~~justified value.

~~$E_{peak} = 8 \times \alpha \times \beta$ (V/km)~~

The earth models used to calculate Table 3 for the United States were obtained from publicly available ~~magnetotelluric data that is~~information published on the U. S. Geological Survey website[3]. The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. ~~NRCan also has developed some models for sub-regions which should be used when available. Because all models in Table 3 are approximations, a planner can substitute a technically justified earth model for its planning area when available.~~A planner can also use specific earth model(s) with

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that ~~cover~~span more than one β scaling factor~~ from Table 3~~, the most conservative (largest) value for β ~~should~~may be used in ~~scaling~~determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could ~~use a tool that is capable of performing~~perform analysis using a non-uniform or piecewise uniform geoelectric field.

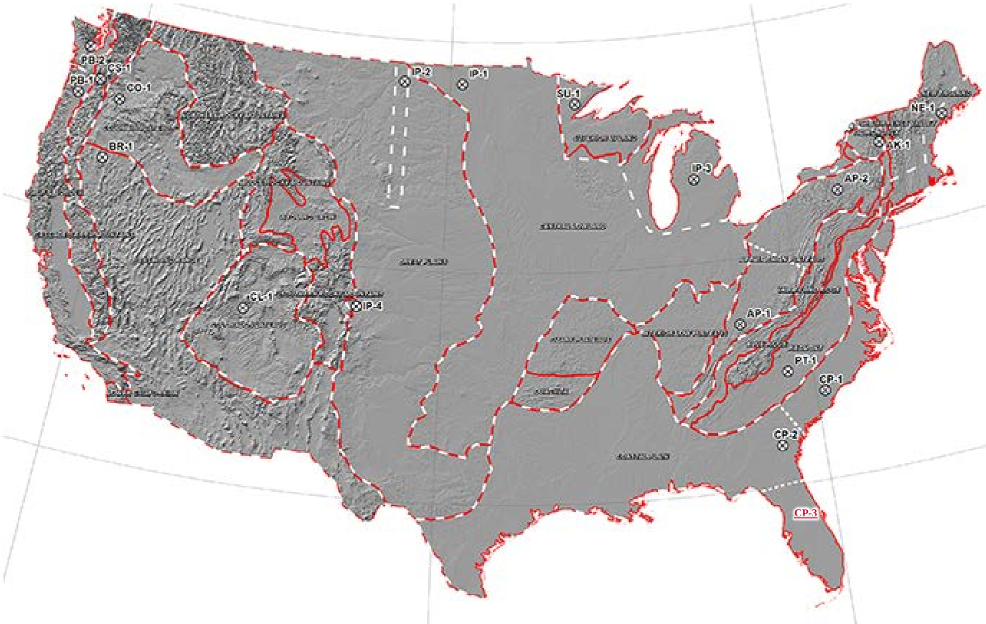


Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	~~.~~0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series where a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

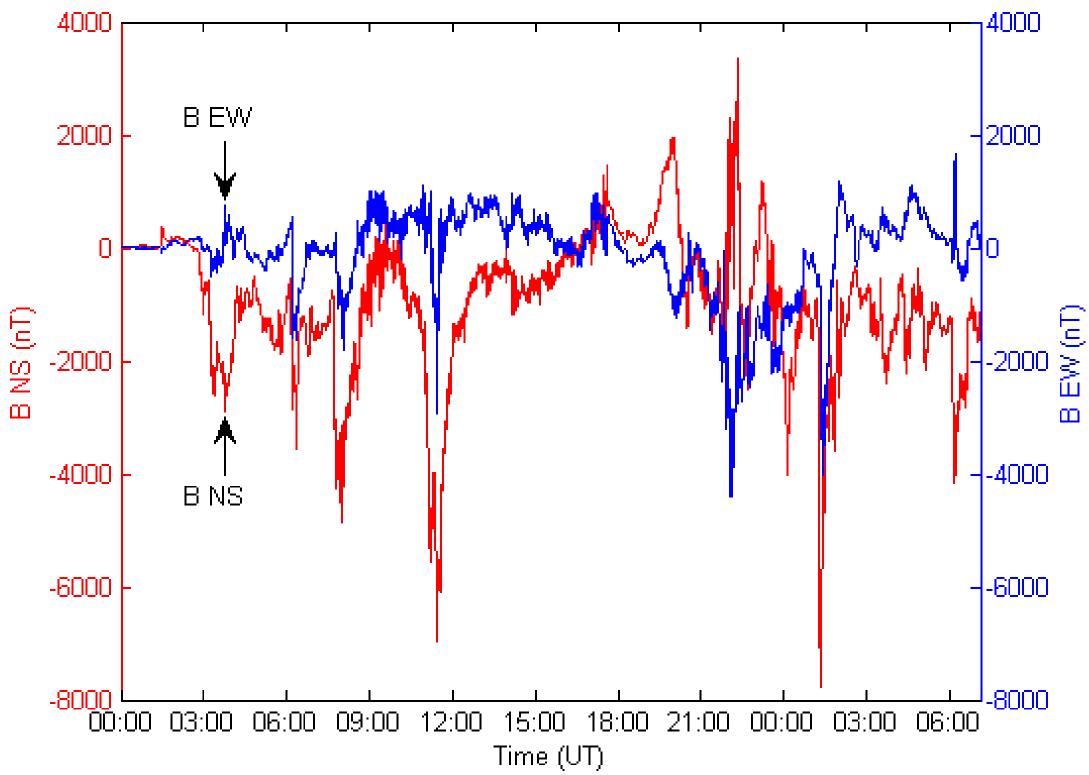


Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

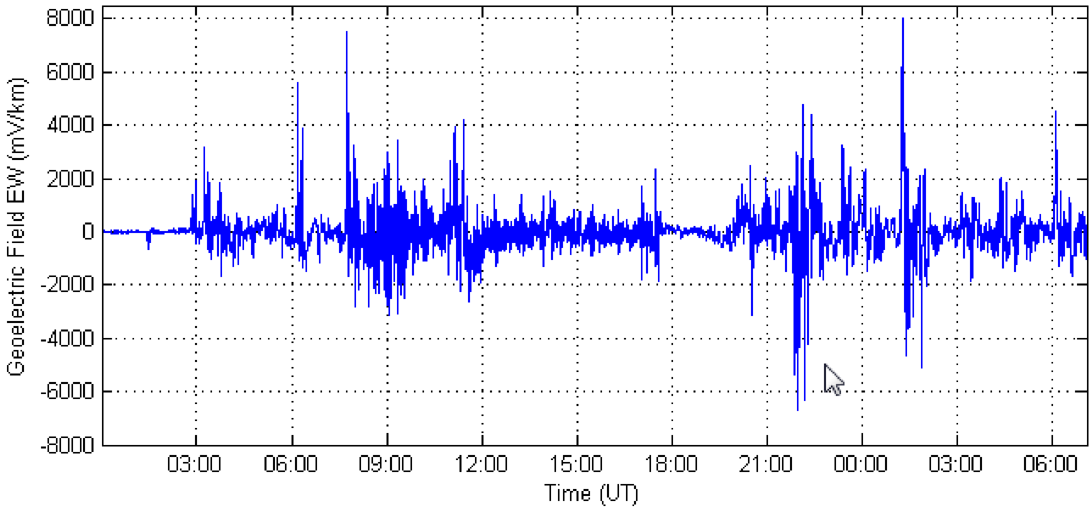


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

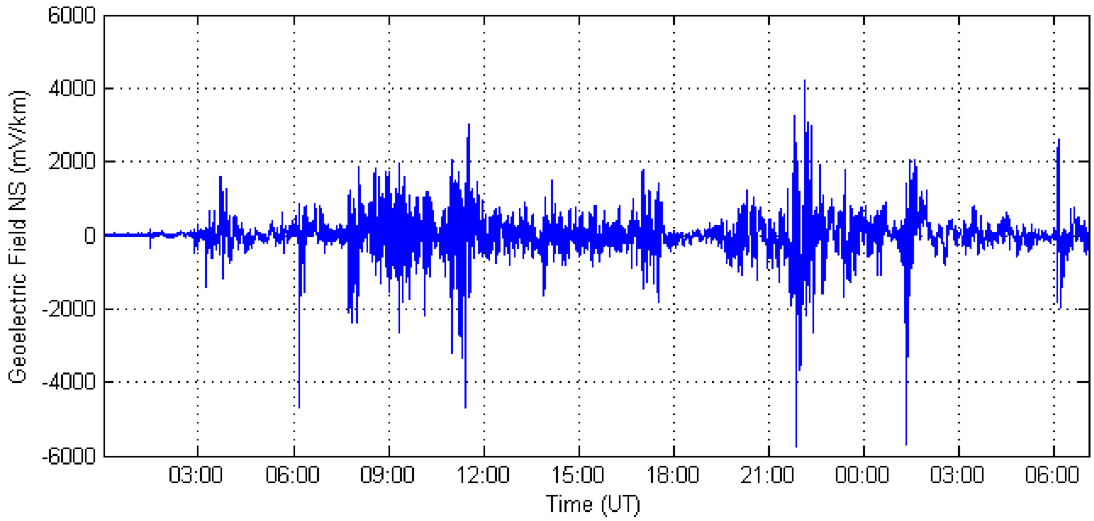


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance ~~Violation~~ Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	Medium	N/A	N/A	~~N/A~~The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and ~~geomagnetically-induced current (~~GIC~~)~~ System models of the responsible entity's planning area for performing the studies needed to complete

						GMD Vulnerability Assessment(s).
R3~~R4~~	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage ~~limits~~ performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4~~R3~~	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD

						Vulnerability Assessment.
R5	Long-term Planning	Medium	N/A	N/A	The responsible entity failed to provide one of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.	The responsible entity failed to provide two of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer; OR The responsible entity did not provide ~~geomagnetically-induced current (GIC)~~GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.
R6	Long-term Planning	~~High~~Medium	The responsible entity failed to conduct ~~an assessment of~~a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable power	The responsible entity failed to conduct ~~an assessment of~~a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned	The responsible entity failed to conduct ~~an assessment of~~a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly	The responsible entity failed to conduct ~~an assessment of~~a thermal impact assessment for more ~~than15%~~than 15% or more than three of its solely owned and jointly owned

			transformers (whichever is greater) where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase; OR The responsible entity conducted ~~an assessment of~~a thermal impact ~~of~~assessment for its solely owned and jointly owned applicable power transformers where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase but did so more than ~~12~~24 calendar months and less than or equal to ~~13~~26 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of	applicable power transformers (whichever is greater) where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase; OR The responsible entity conducted ~~an assessment of~~a thermal impact ~~of~~assessment for its solely owned and jointly owned applicable power transformers where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase but did so more than ~~13~~26 calendar months and less than or equal to ~~14~~28 calendar months of receiving GIC flow information specified in Requirement R5; OR	owned applicable power transformers (whichever is greater) where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase; OR The responsible entity conducted ~~an assessment of~~a thermal impact ~~of~~assessment for its solely owned and jointly owned applicable power transformers where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase but did so more than ~~14~~28 calendar months and less than or equal to ~~15~~30 calendar months of receiving GIC flow information specified in Requirement R5; OR	applicable power transformers (whichever is greater) where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase; OR The responsible entity conducted ~~an assessment of~~a thermal impact ~~of~~assessment for its solely owned and jointly owned applicable power transformers where the maximum effective ~~geomagnetically-induced current (~~GIC~~)~~ value provided in Requirement R5 part 5.1 is 15 ~~Amperes~~A or greater per phase but did so more than ~~15~~30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include four of the required elements as

			the required elements as listed in Requirement R6 parts 6.1 through 6.4.	The responsible entity failed to include two of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	The responsible entity failed to include three of the required elements as listed in Requirement R6 parts 6.1 through 6.4.	listed in Requirement R6 parts 6.1 through 6.4.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 parts 7.1 ~~and~~through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 parts 7.1 ~~and~~through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 parts 7.1 ~~and~~through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

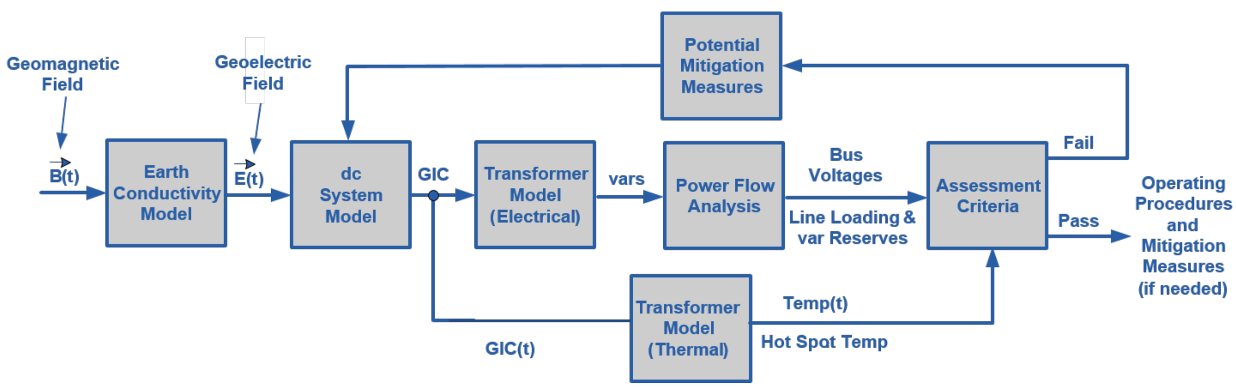
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement ~~R3~~R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC time series information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC system model and must be provided to the entity responsible for conducting the thermal impact assessment.

The maximum effective GIC value provided in part 5.1 is used to screen the transformer fleet such that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.

The effective GIC time series, GIC(t), provided in part 5.2 is used to conduct the transformer thermal impact assessment (see white paper for details).

The peak GIC value of 15 amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low. Additional information is ~~available~~ in the ~~transformer thermal impact assessment white paper:~~following section.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2 is also a justifiable threshold criteria that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required,

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a ~~Planning Coordinator~~ planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a ~~Transmission Planning~~planning area that includes an applicable power transformer as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a ~~4~~5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is ~~60 calendar days~~six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is ~~60 calendar days~~six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is ~~14 calendar~~18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is ~~14 calendar~~18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is ~~18 calendar~~24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is ~~18 calendar~~24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is ~~36 calendar~~48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R6 shall become effective on the first day of the first calendar quarter that is ~~36 calendar~~48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is ~~48 calendar~~60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is ~~48 calendar~~60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by October 10, 2014.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages. Project 2013-03 responds to the FERC directives as follows:

- Stage 1. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June, 2014.
- Stage 2. Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the proposed standard will require the applicable entity to develop corrective actions to mitigate the risk of voltage collapse, uncontrolled separation, or Cascading. The Stage 2 standard must be filed with FERC by January 2015.

A draft of TPL-007-1 and supporting white papers were posted for informal comments from June 13 – July 30, 2014. The standard drafting team (SDT) has made several revisions based on stakeholder input.

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

Questions on Draft TPL-007-1

1. **TPL-007-1**. Do you agree with the changes made to TPL-007-1? If not, please provide a specific recommendation for revisions you could support and justification to support the proposed revisions.

   ☐ Yes
   ☐ No

   Comments:

2. **Implementation**. The SDT has revised the proposed Implementation Plan from an overall four-year implementation to five years based on stakeholder comments. Do you agree with the changes made to the Implementation Plan? If not, please provide a specific recommendation and justification.

   ☐ Yes
   ☐ No

   Comments:

3. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL)**. The SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for TPL-007-1? If you do not agree, please explain why and provide recommended changes.

   ☐ Yes
   ☐ No

   Comments:

4. Are there any other concerns with the proposed standard or white papers that have not been covered by previous questions and comments? If so, please provide your feedback to the SDT.

   ☐ Yes
   ☐ No

   Comments:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
Draft: August 21, 2014

RELIABILITY | ACCOUNTABILITY



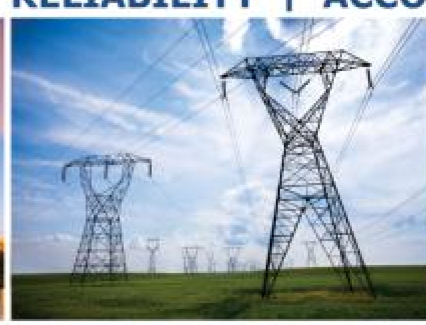
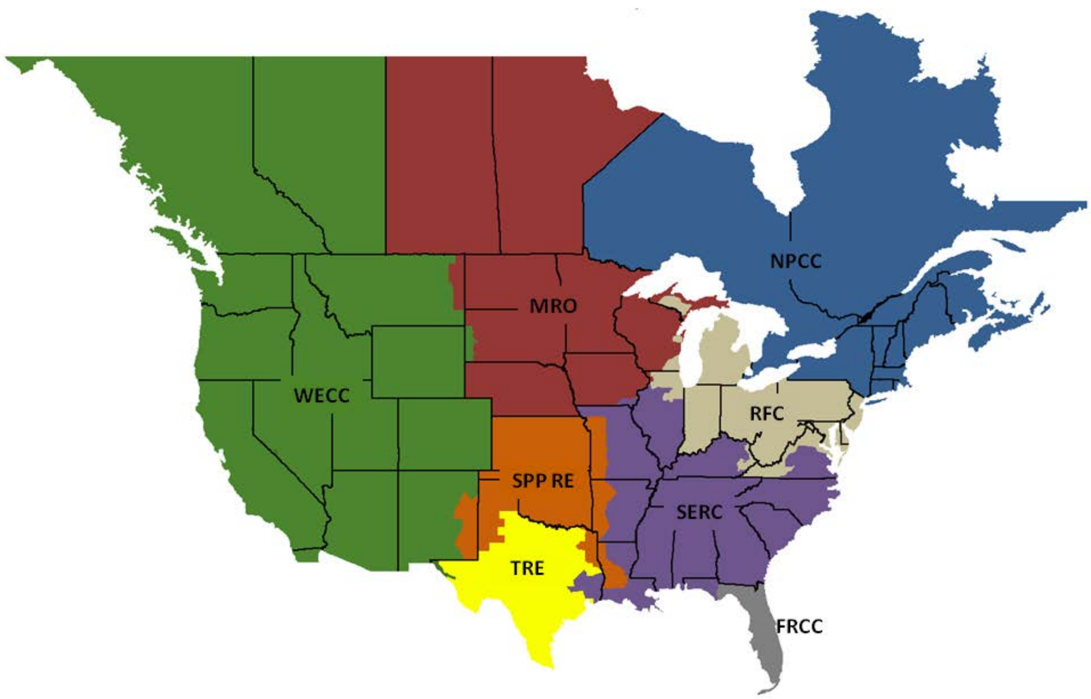



Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

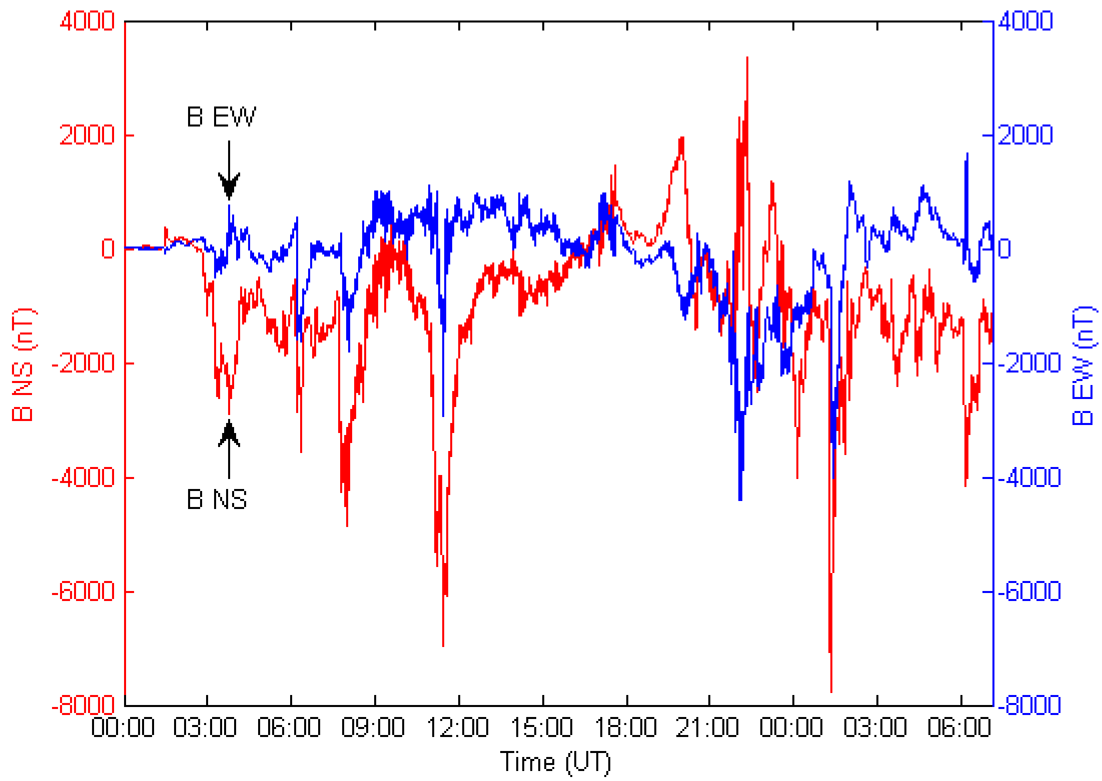


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

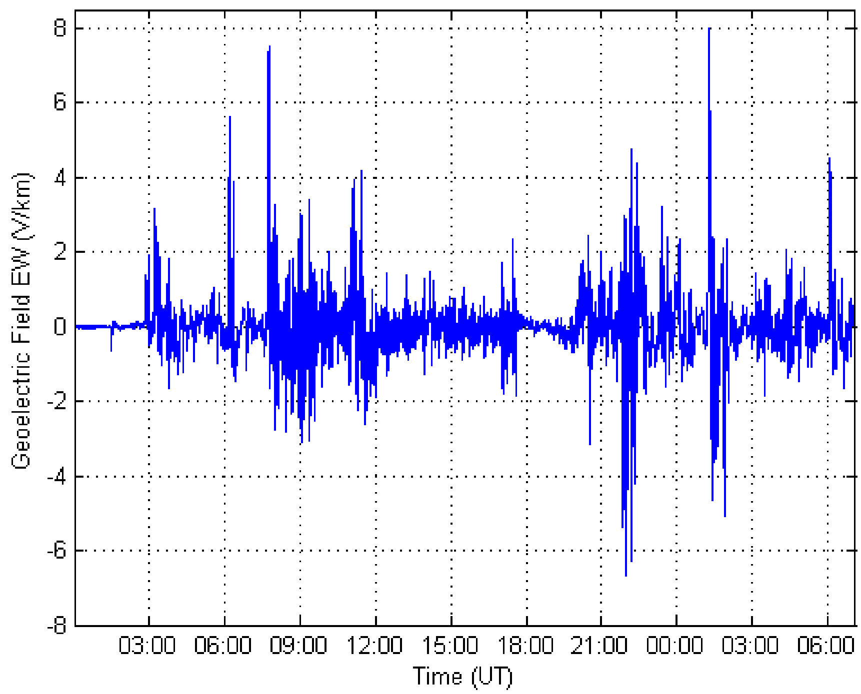


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

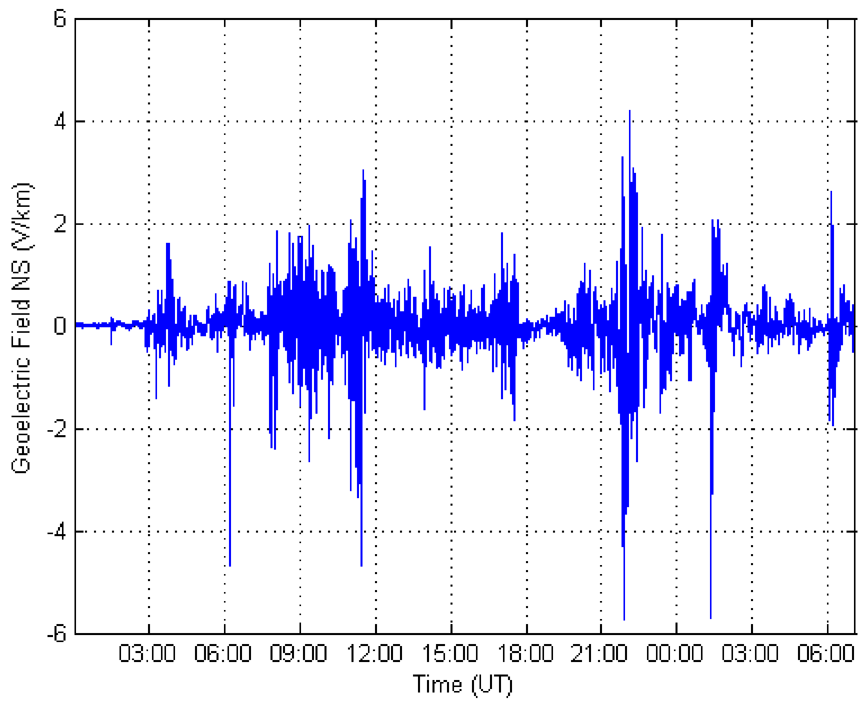


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

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[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

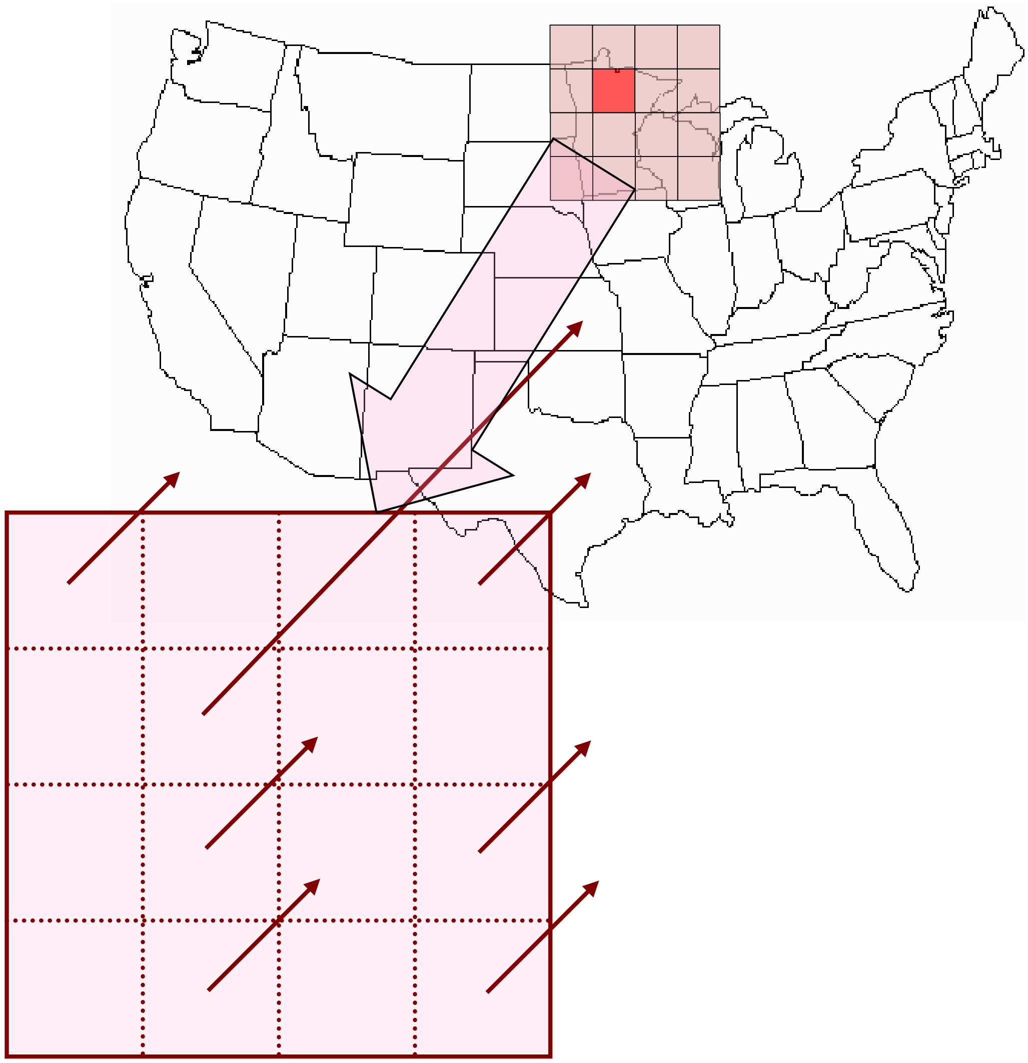


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

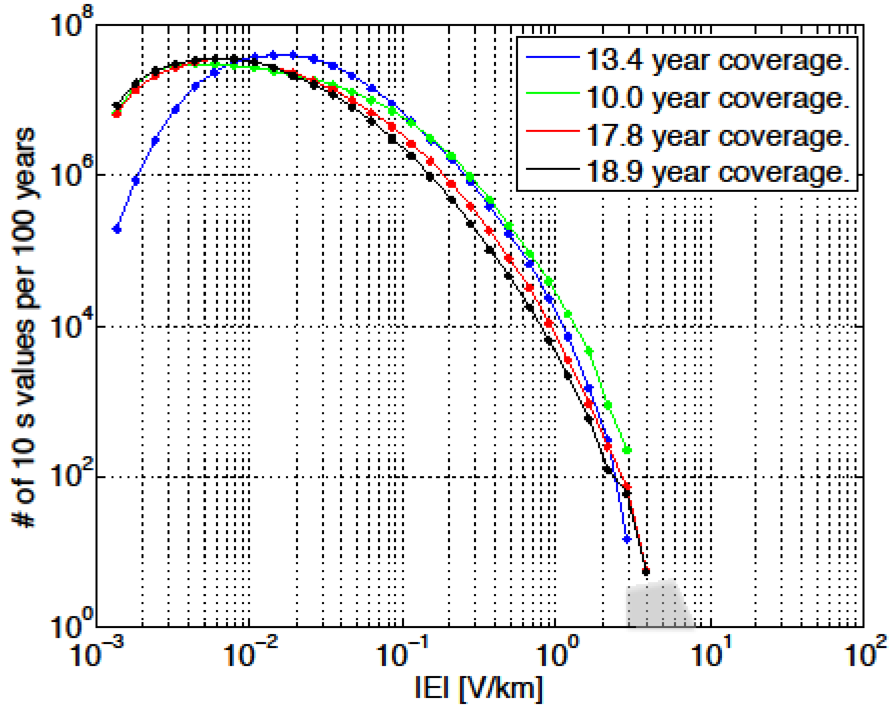


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

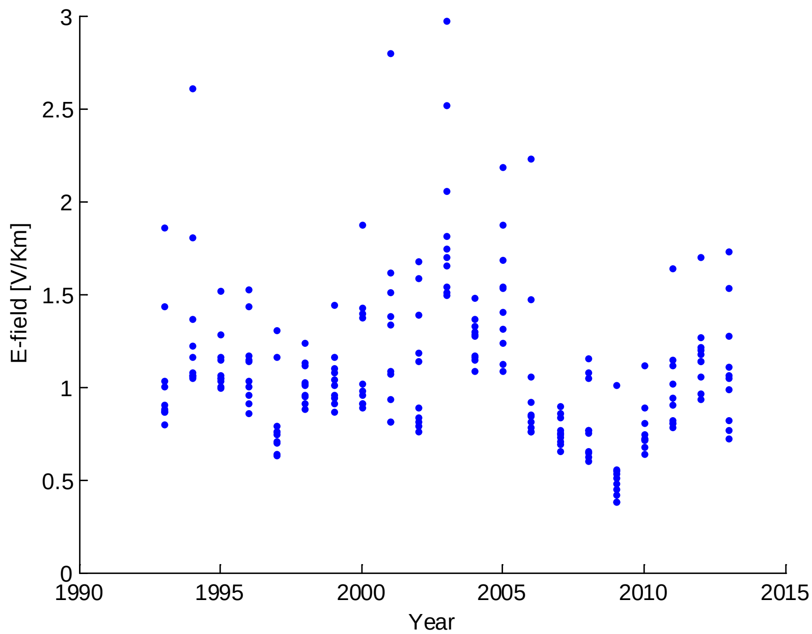


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: α_1=0, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

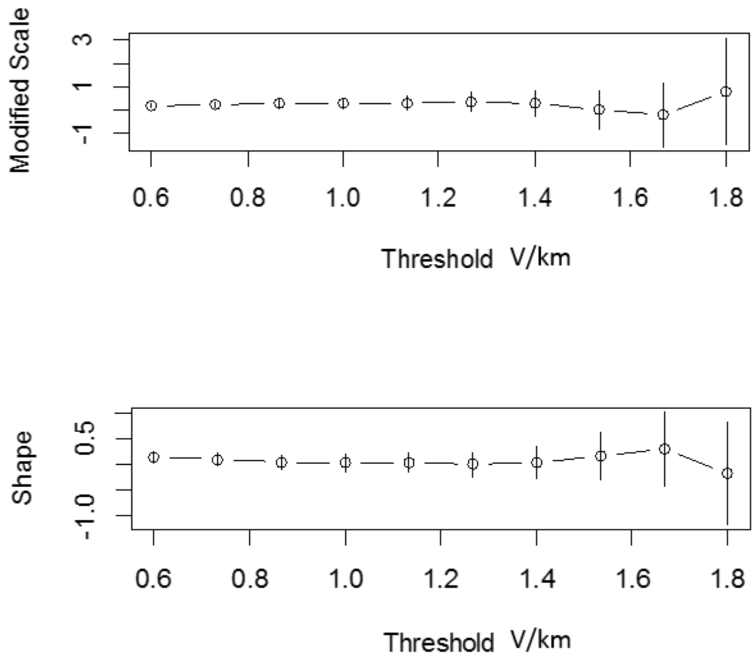


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

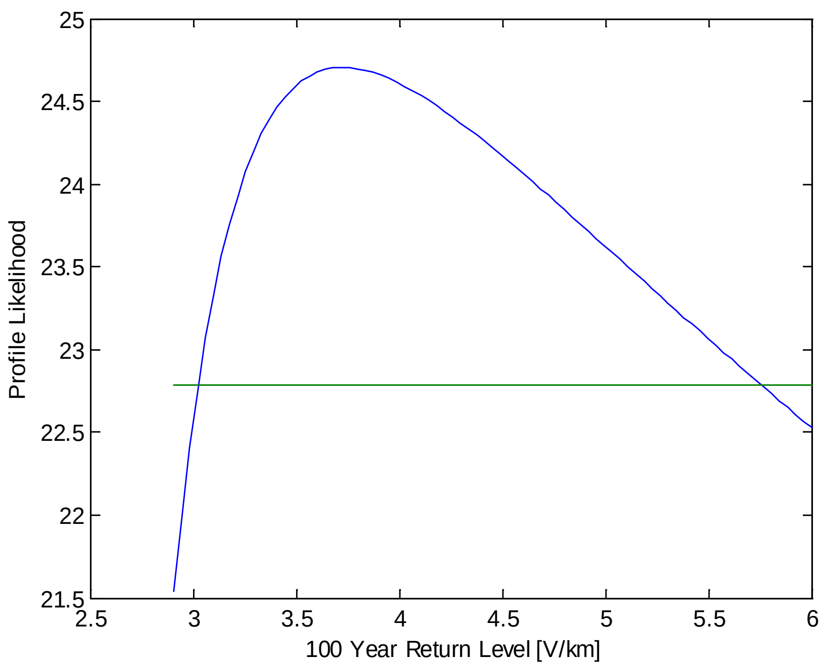


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

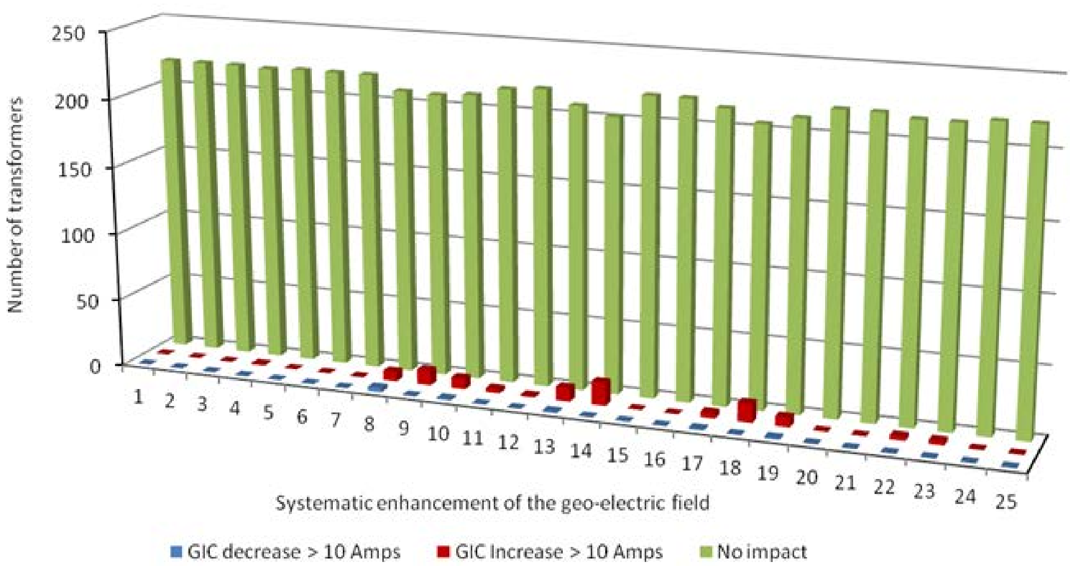


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

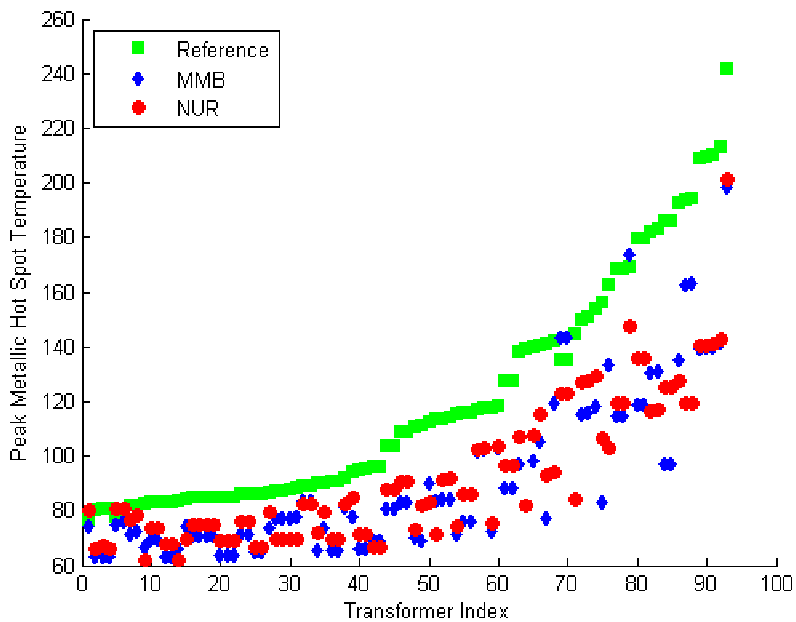


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

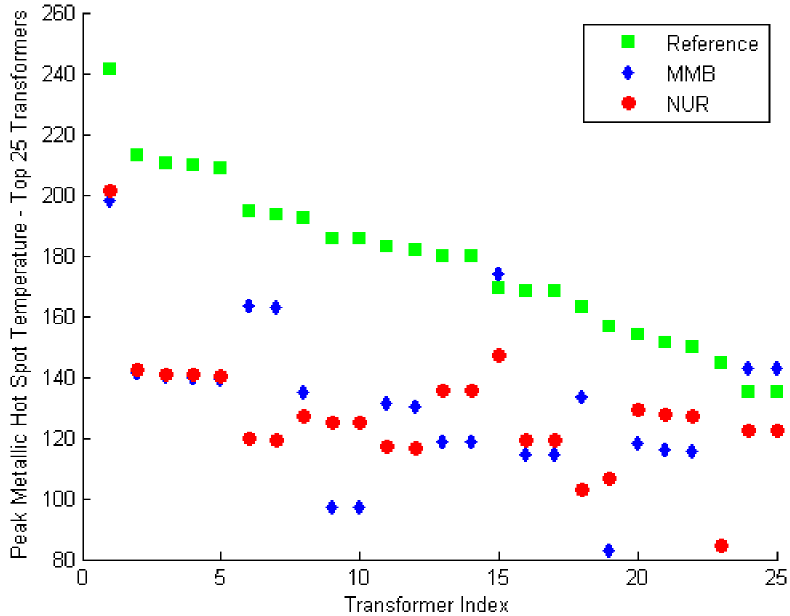


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1.0$.

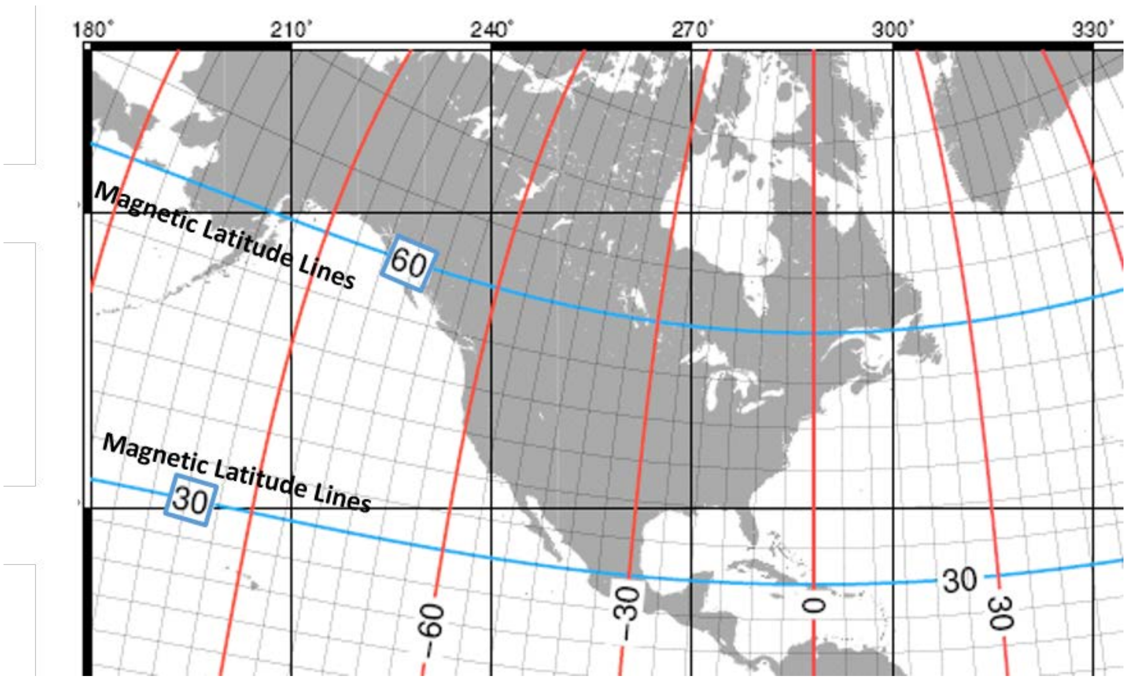


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \tag{II.2}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

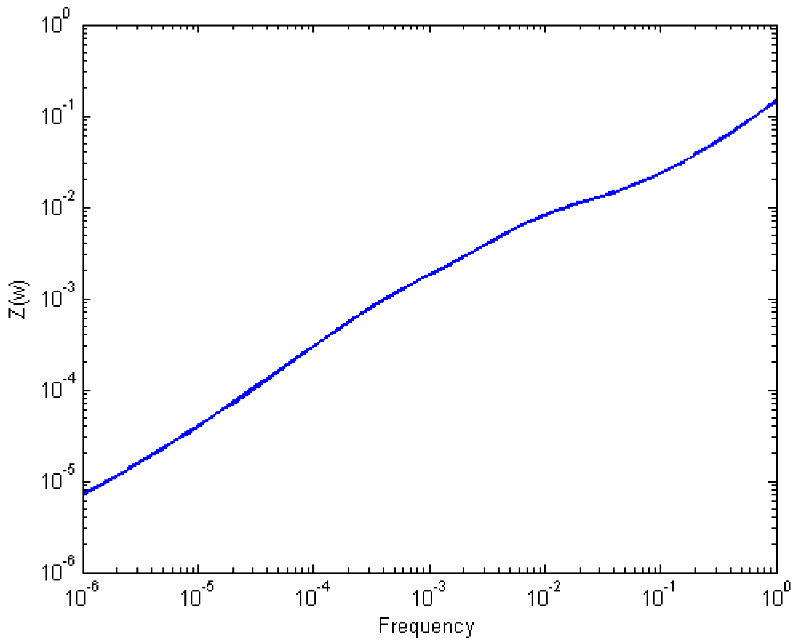


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

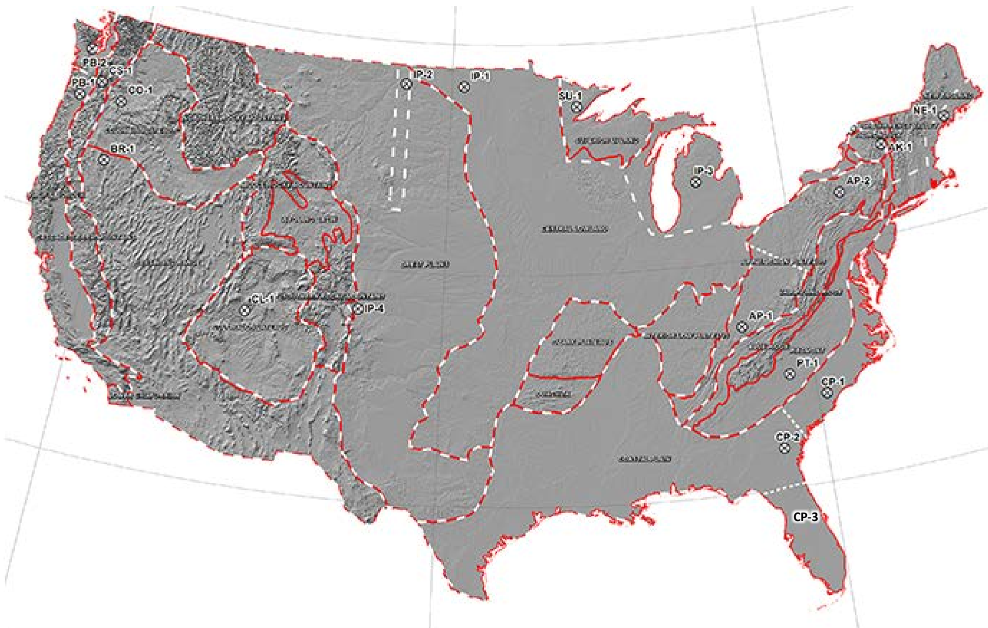
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \qquad \text{(II.3)}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use a β factor of 1 or other technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

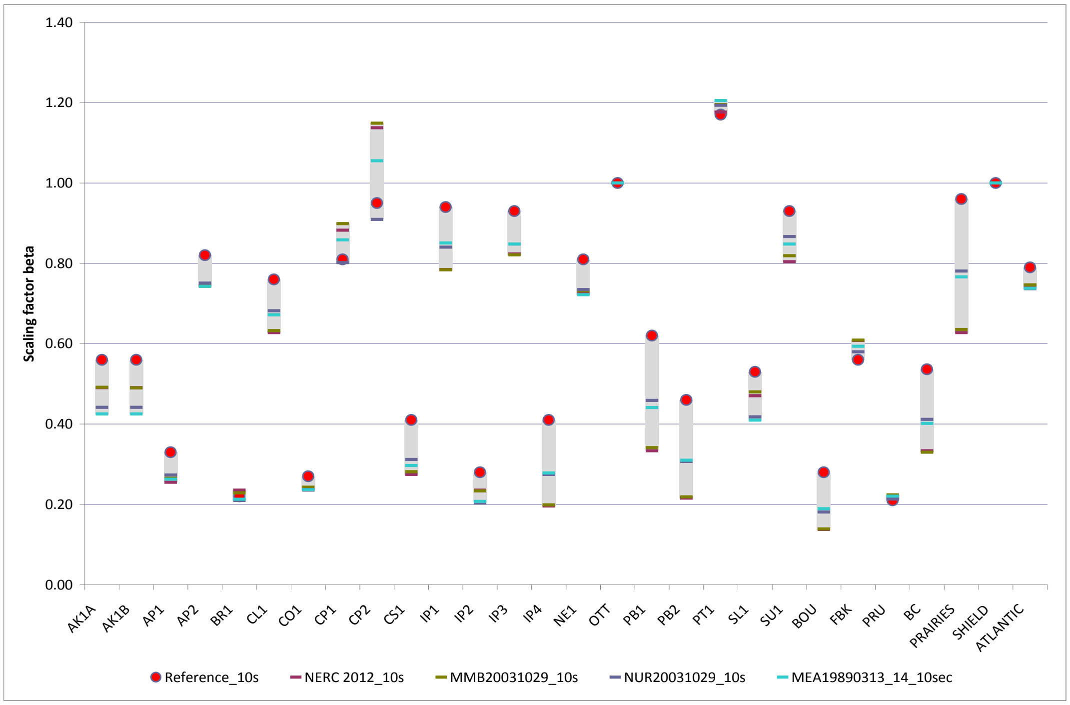


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V / km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation

Standard Drafting Team

Draft: ~~June 10~~August 21, 2014

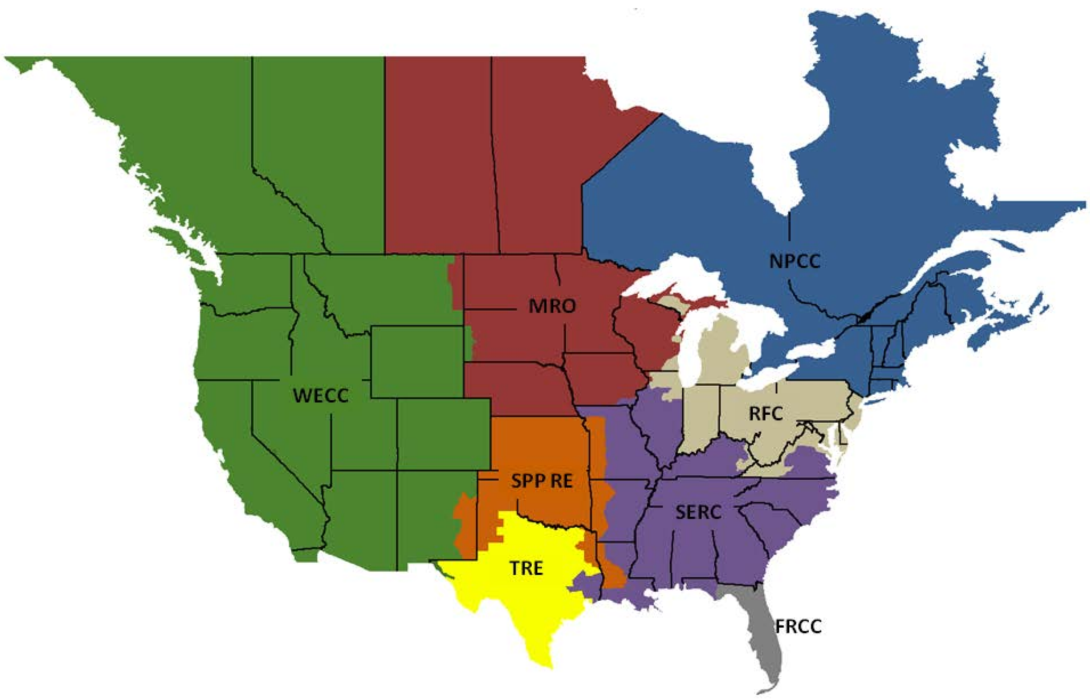
RELIABILITY | ACCOUNTABILITY

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations ~~is pending at~~was approved by FERC in ~~Docket No. RM14-1-000~~June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. ~~-~~The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

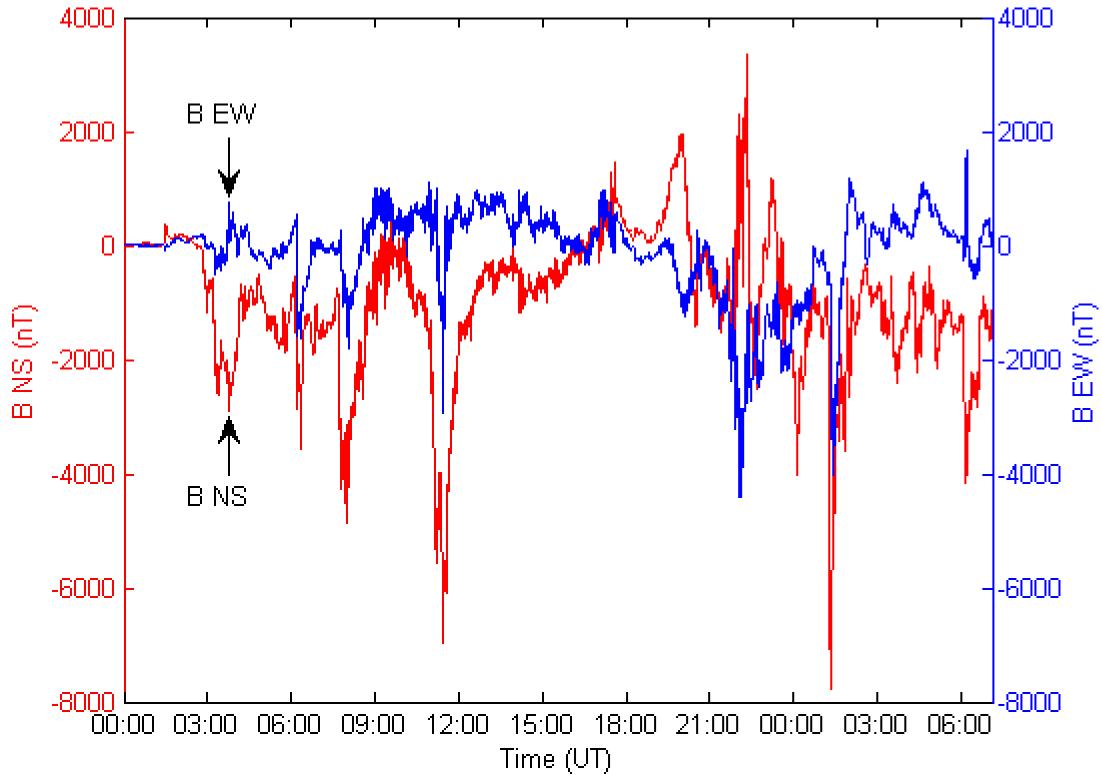


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

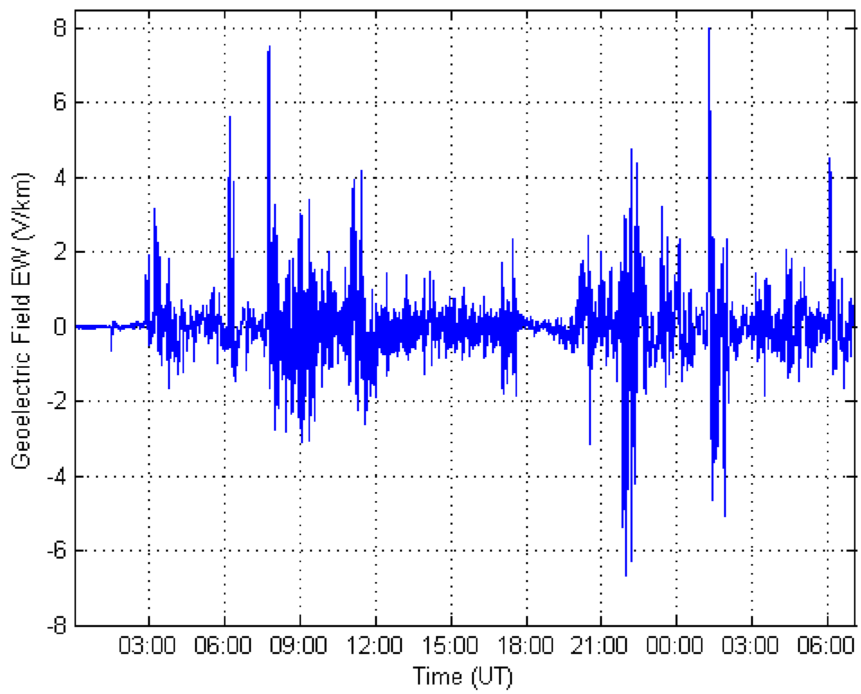


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

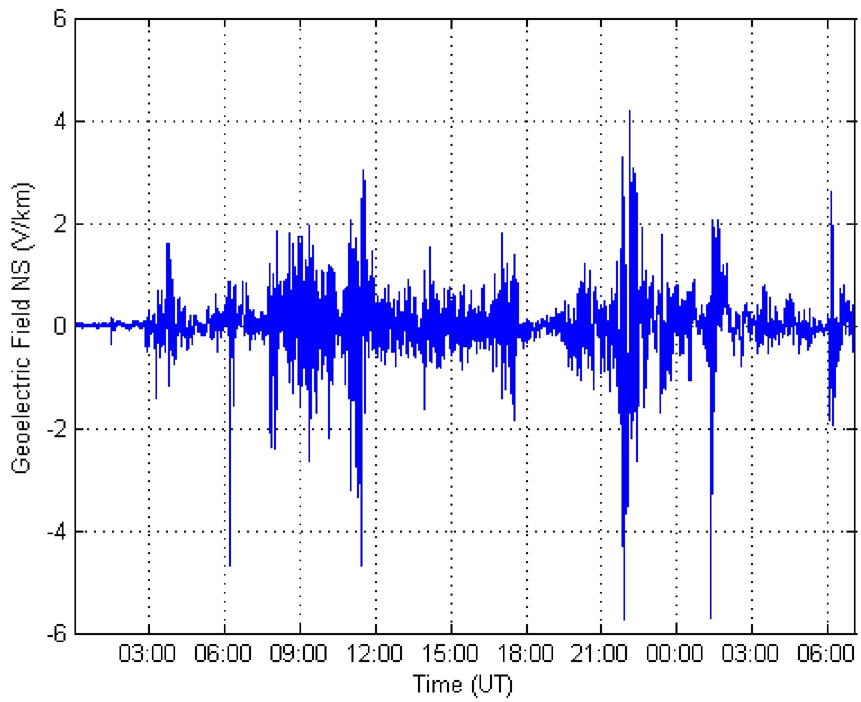


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a~~ny one~~ particular area is more likely to experience a localized enhanced geoelectric field.

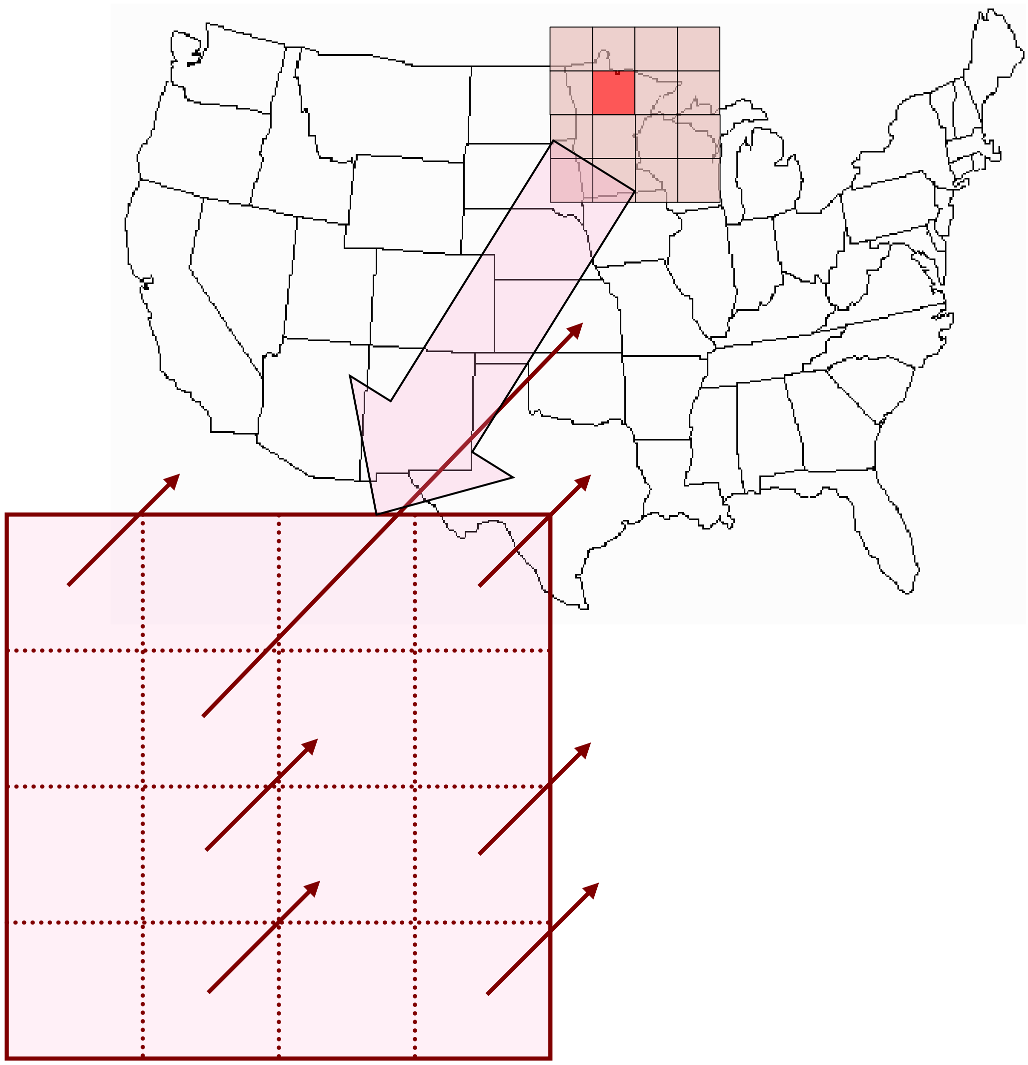


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

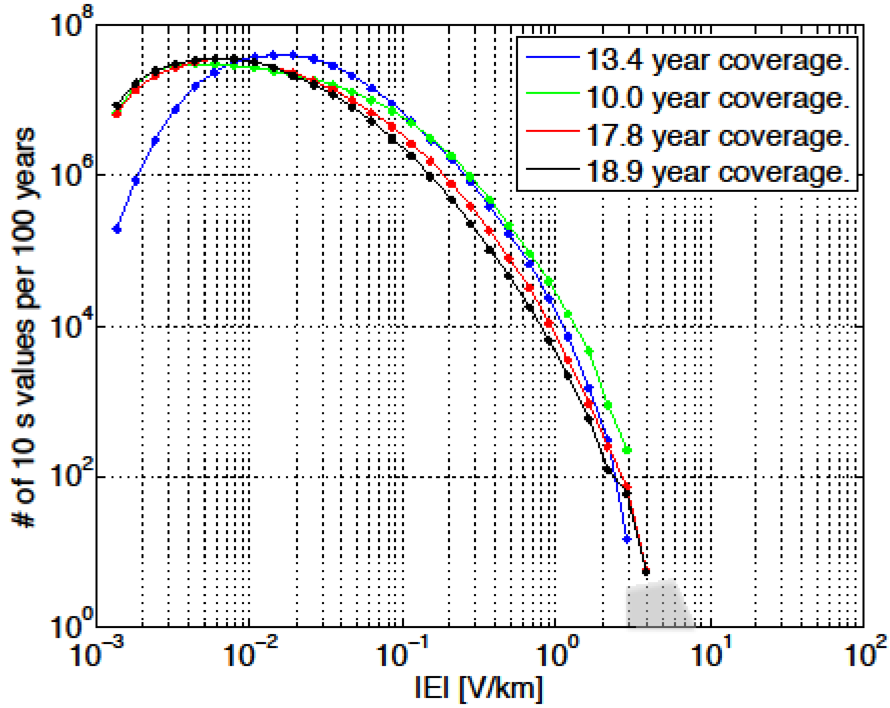


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. ~~Dashed lines represent the values predicted with extreme value analysis.~~ The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geo-electric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

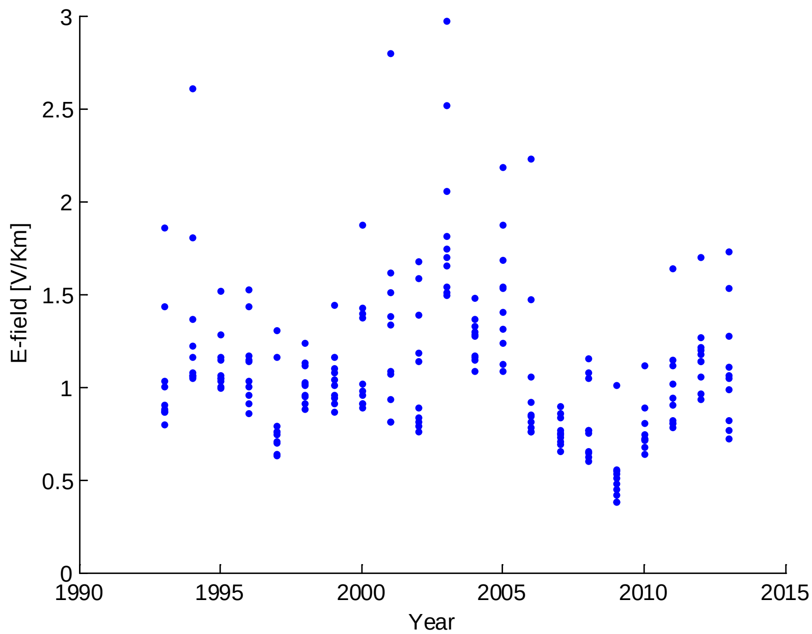


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples ~~we~~ were ~~to~~ obtained ~~repeated samples~~, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: α_1=0, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: ~~-~~[2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. ~~shows that the geoelectric field amplitude of 8 V/km for the benchmark is conservative for a 100-year return level and it includes an implicit 25 percent engineering margin~~.

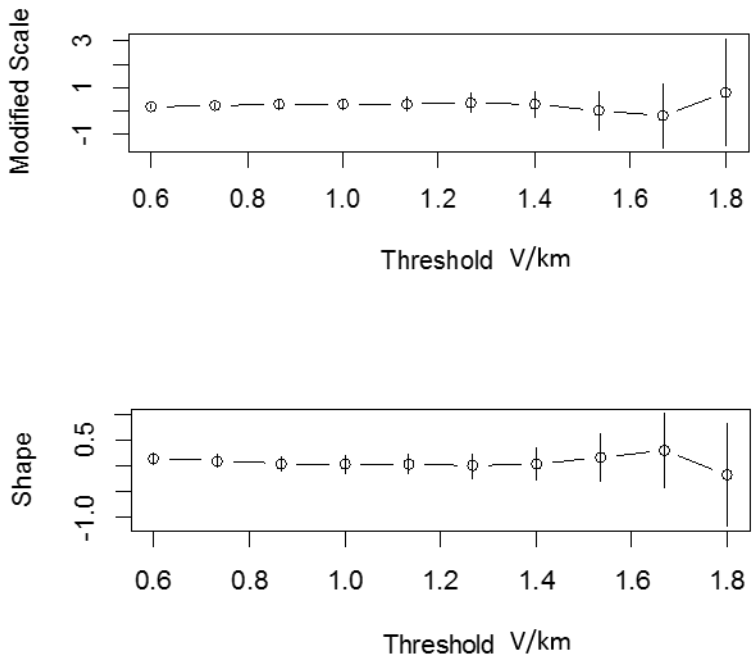


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

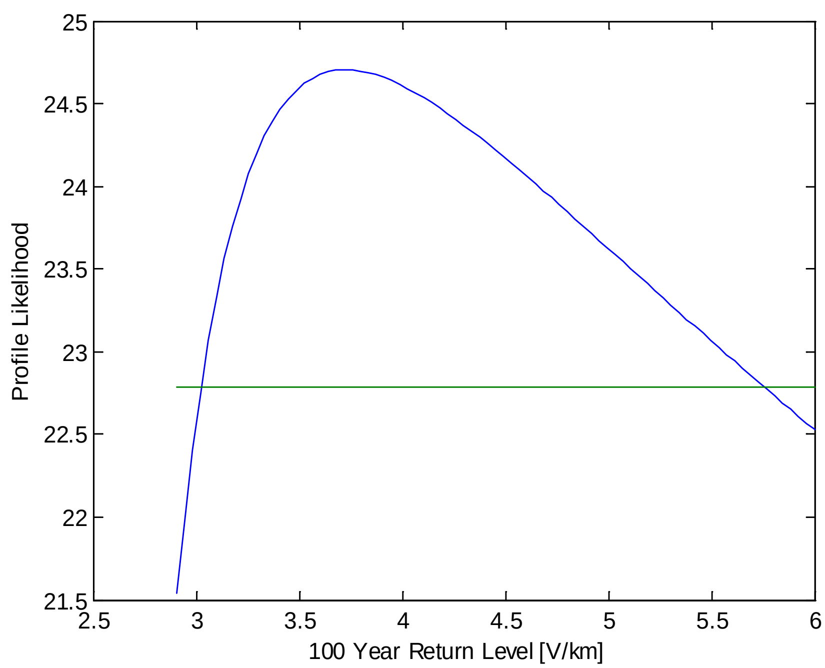


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

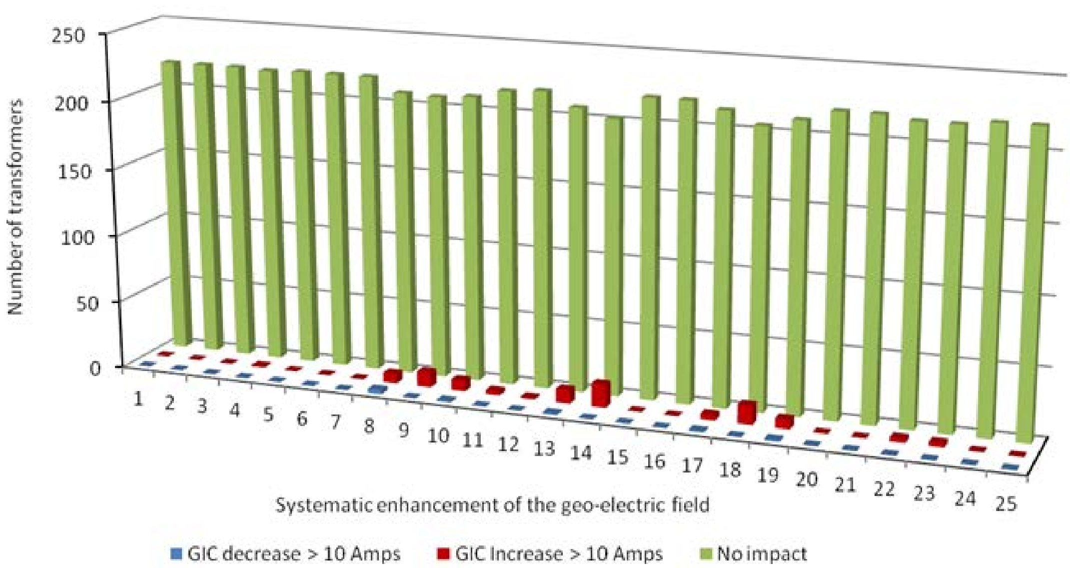


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

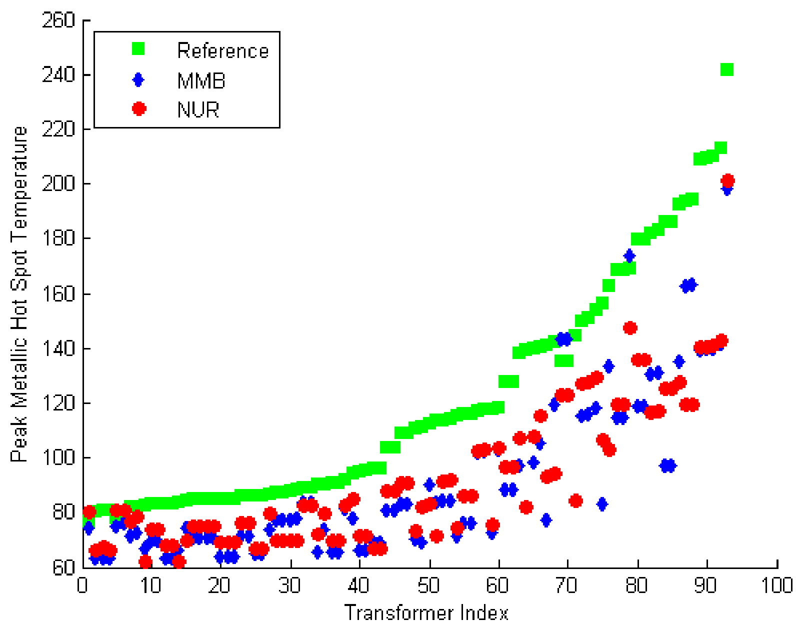


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

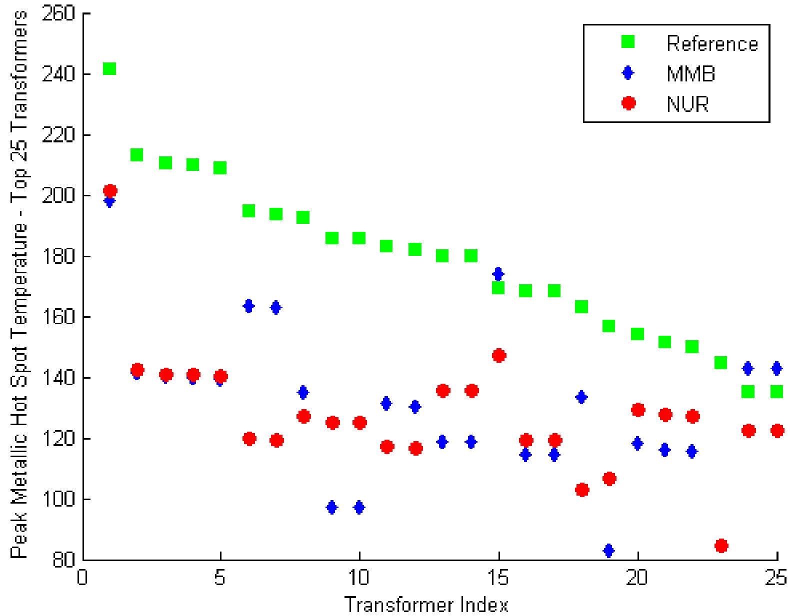


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]. Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \tag{II.1}$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1.0$.

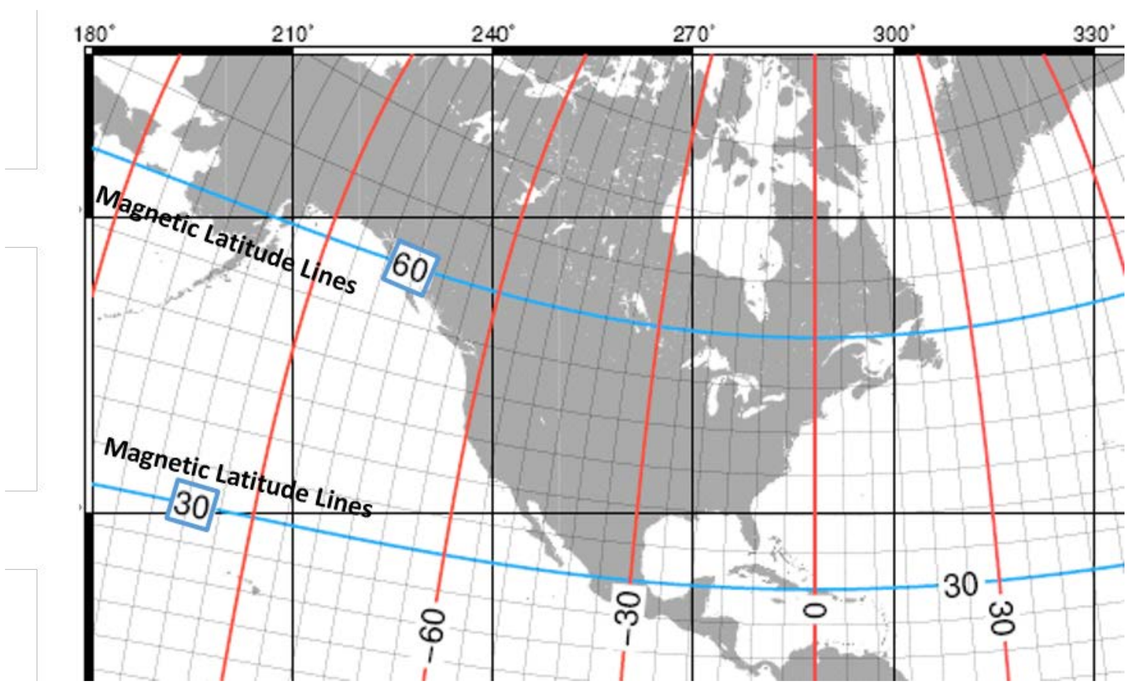


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \qquad \text{(II.2)}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

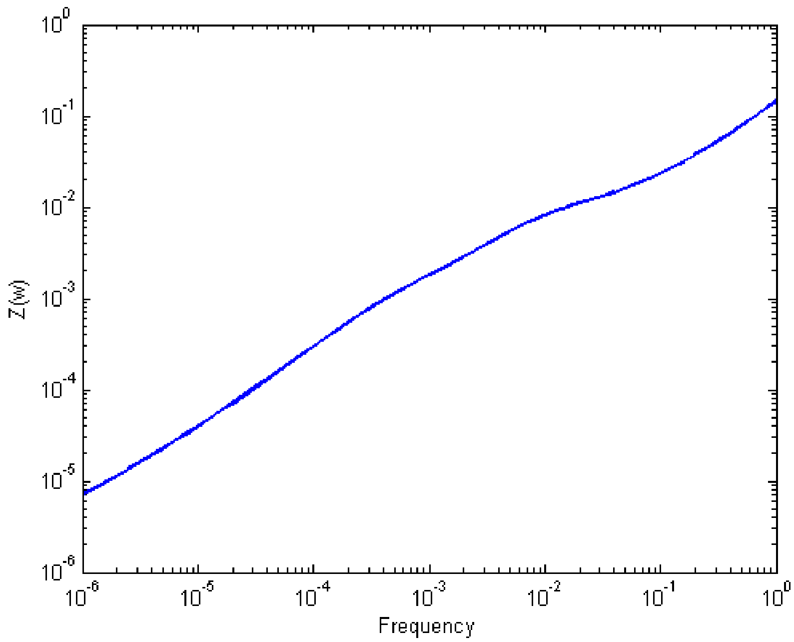


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

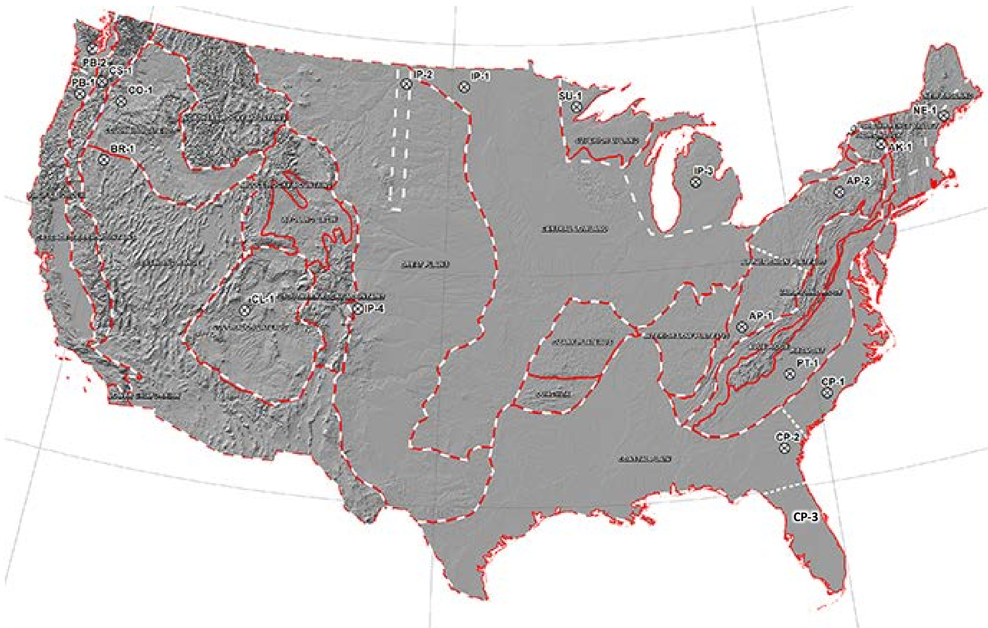
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \qquad \text{(II.3)}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from ~~magnetotelluric data and are~~published information available ~~from~~ on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, ~~these will all be different~~there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use a β factor of 1 or other technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

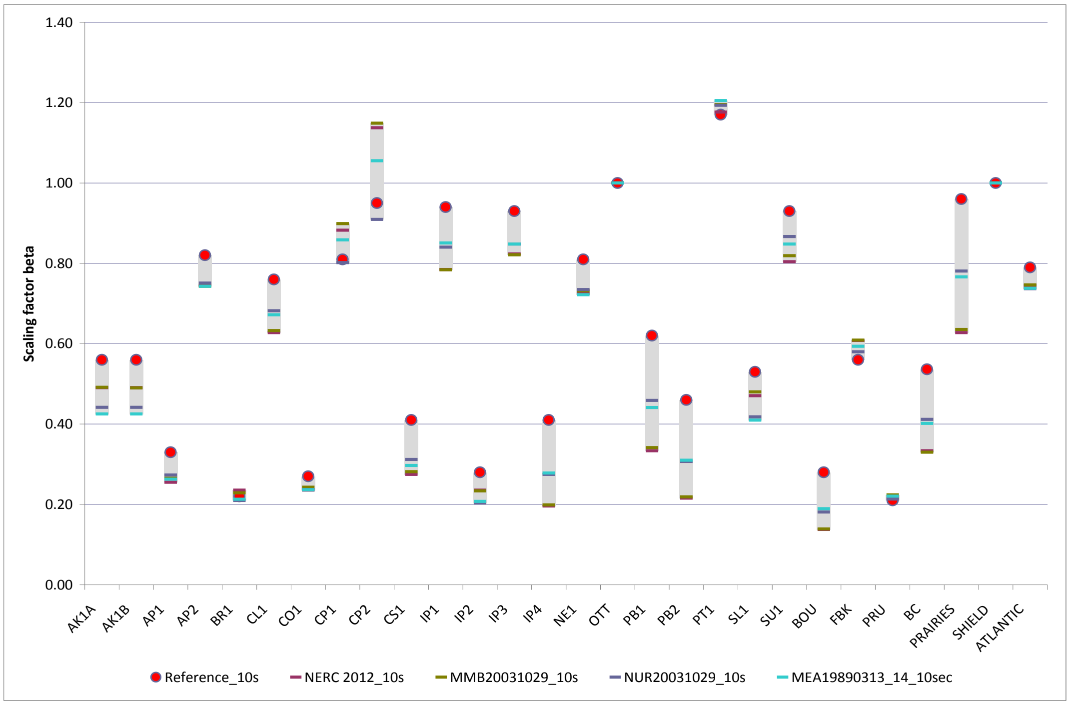


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond~~s~~ to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than~~t~~ the reference benchmark conductivity, ~~and~~ therefore, according to the conductivity factor β from Table II-2., t~~T~~he calculation follows~~n~~:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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Transformer Thermal Impact Assessment White Paper (Draft)

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

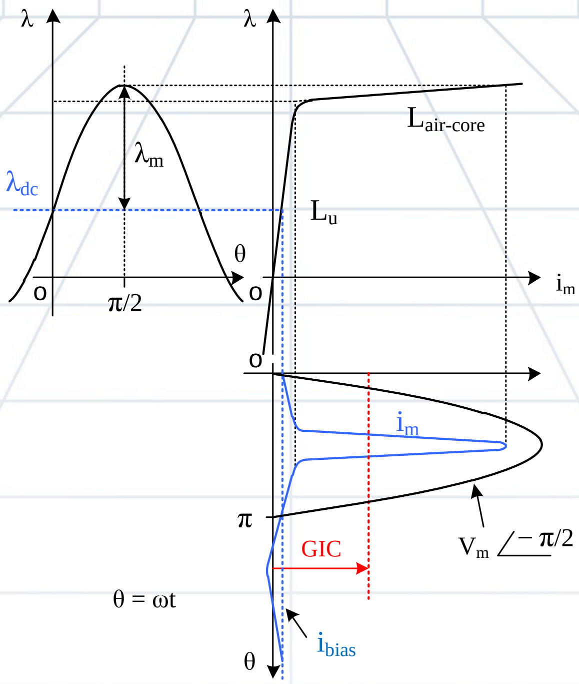

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2]

$$I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H \tag{1}$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

There are two different ways to carry out a detailed thermal impact screening:

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

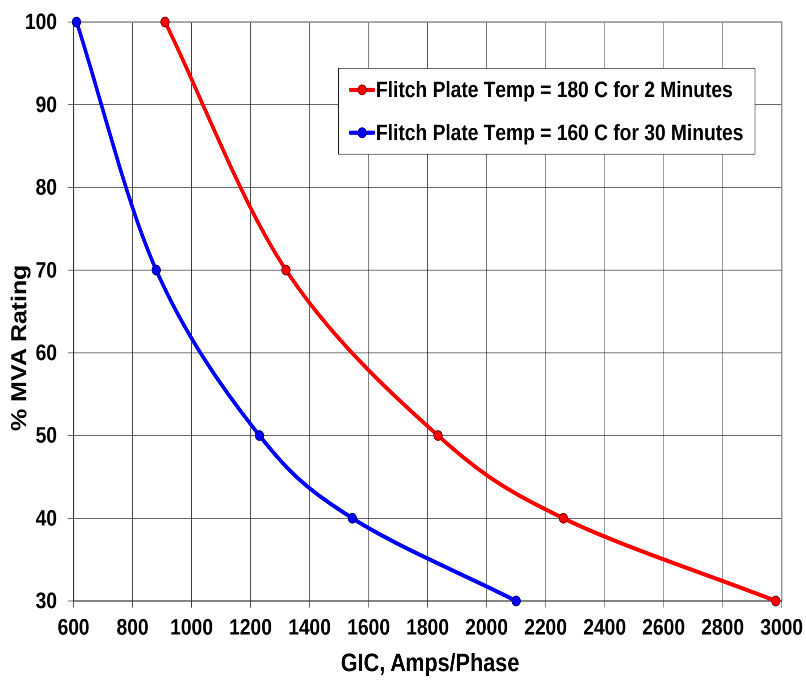

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in

[1] Technical details of this methodology can be found in [4].

Figure 3. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std. C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

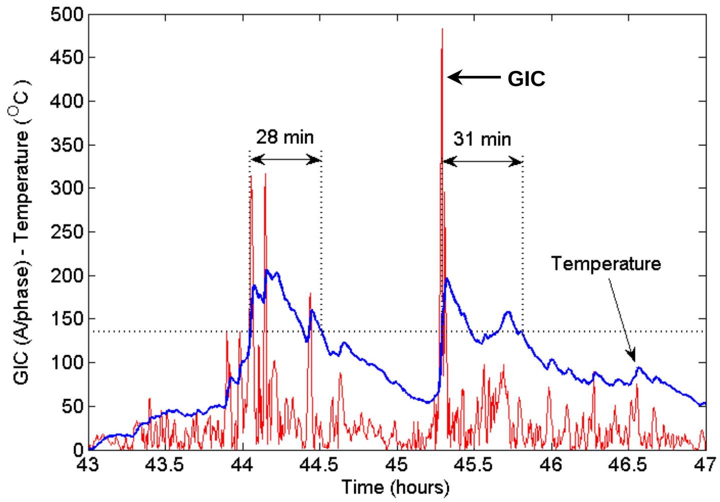

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;

2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase/V/km) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \tag{2}$$

where

$$\left|E(t)\right| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km.

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N$ (A/phase)

---

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

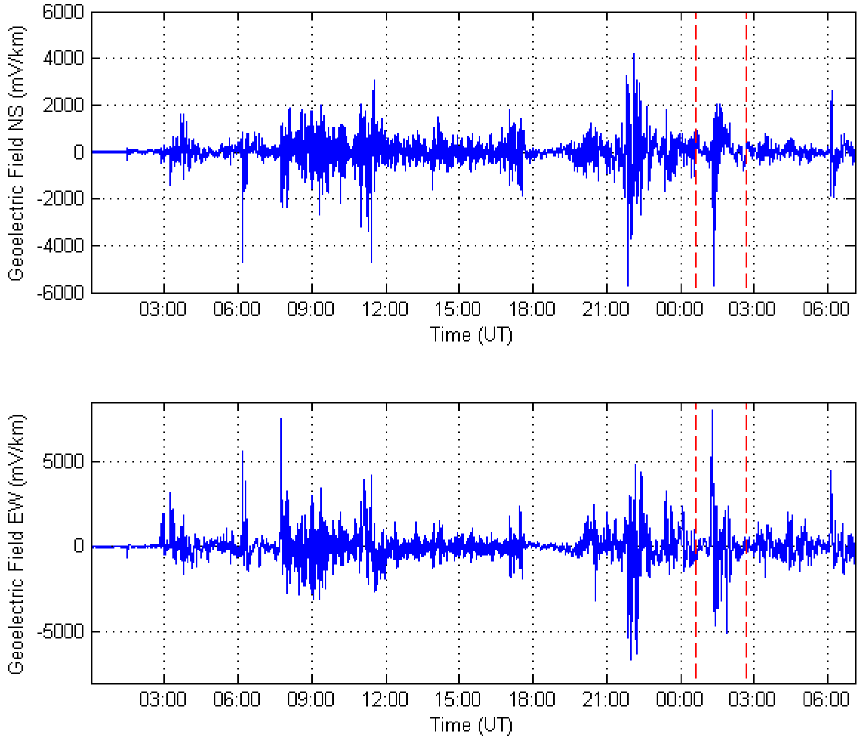

Figure 4: Calculated Geoelectric Field E_N(t) and E_E(t) Assuming α=1 and β=1 (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

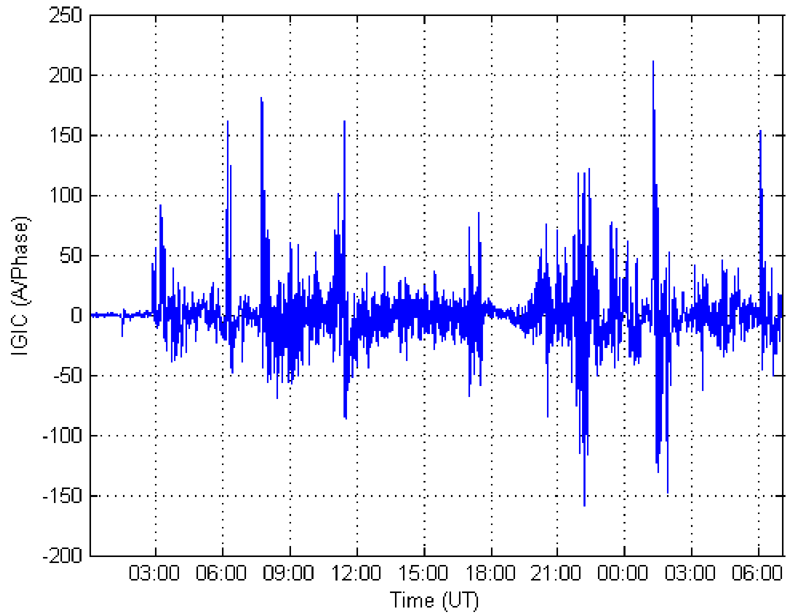

Figure 5: Calculated GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

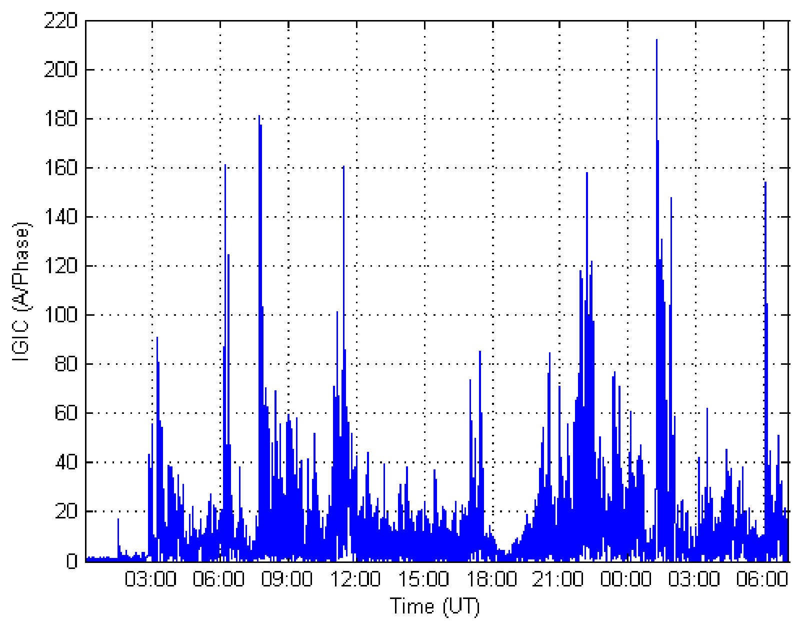

Figure 6: Calculated Magnitude of GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

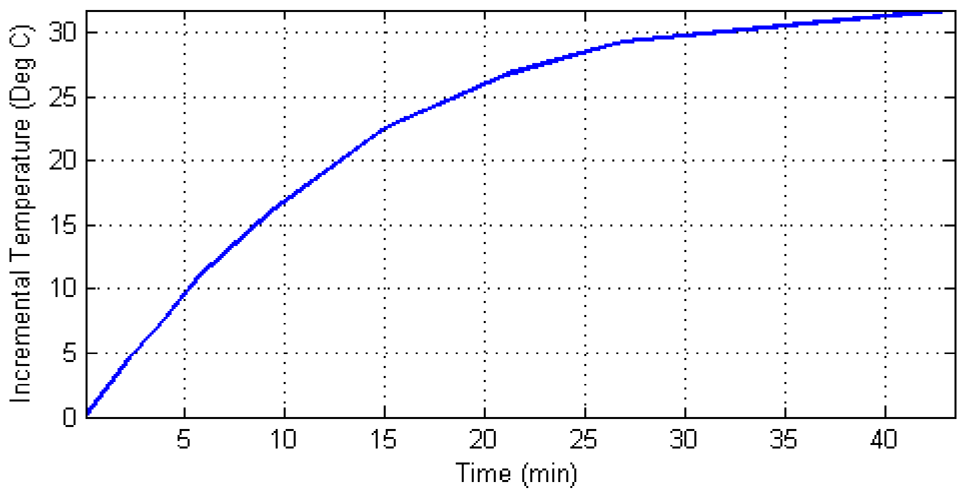

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step

Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

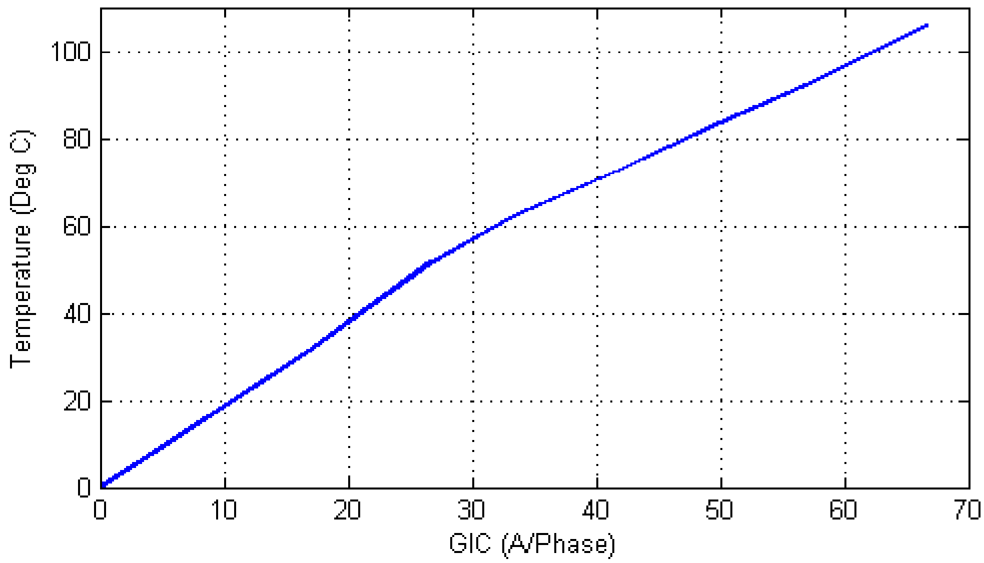

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

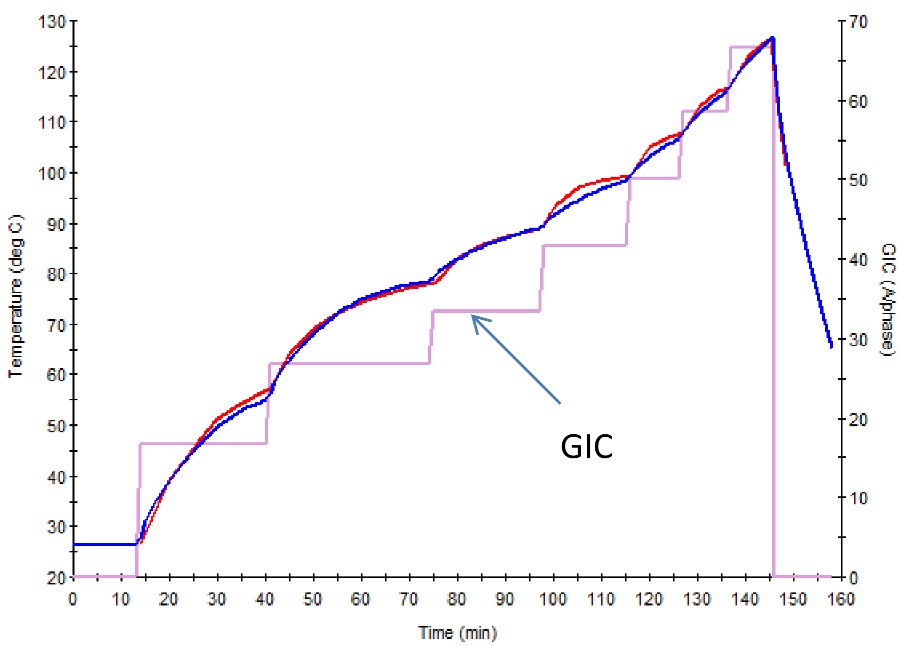

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time θ(t) for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

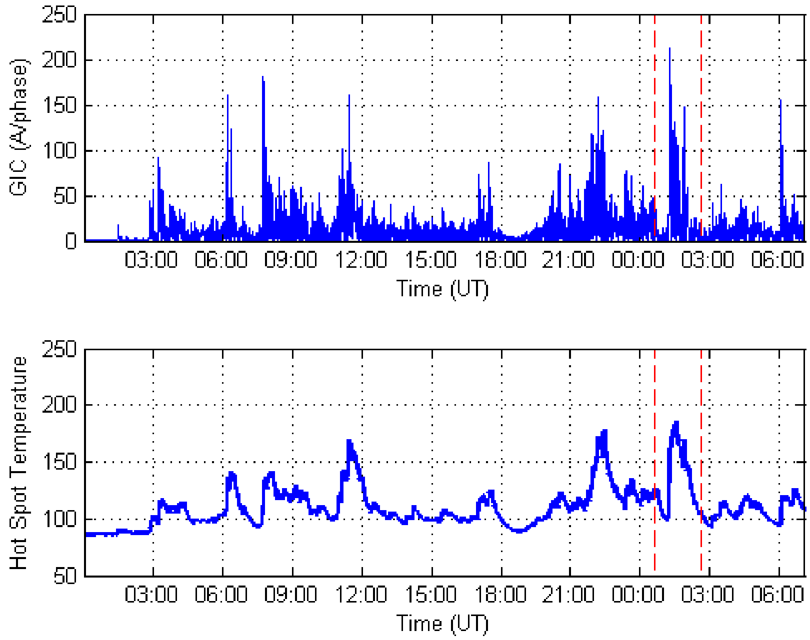

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

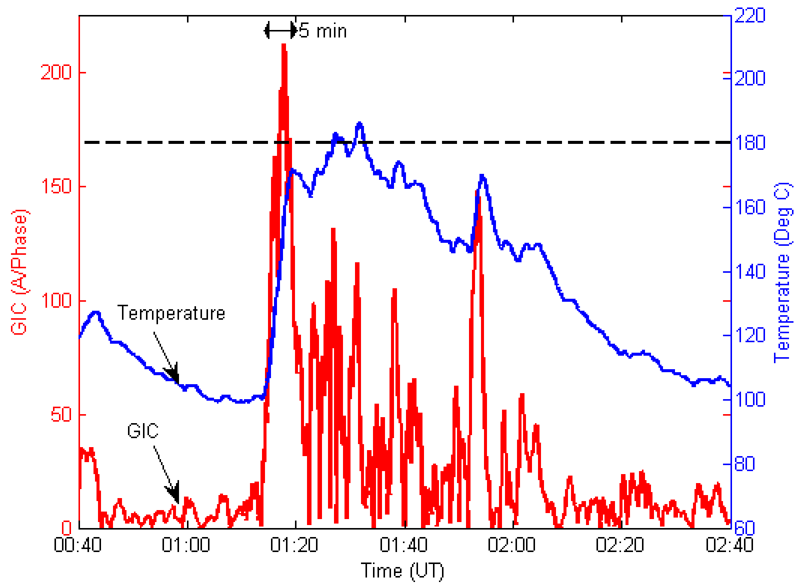

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std. C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

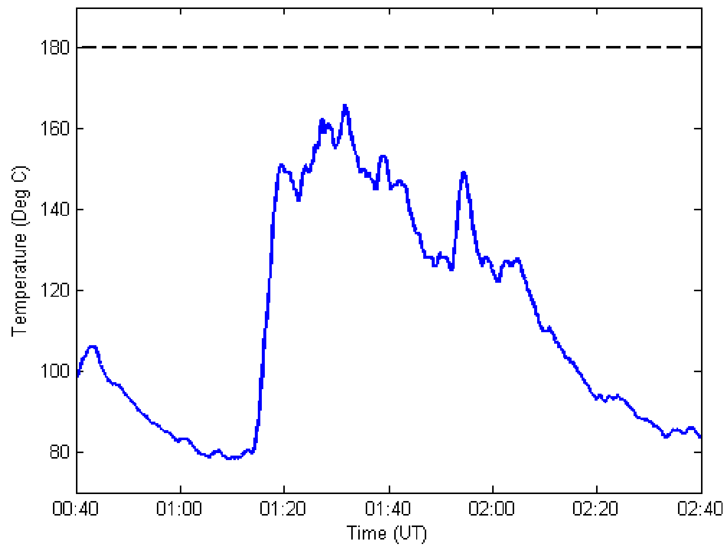

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std. C57.91).

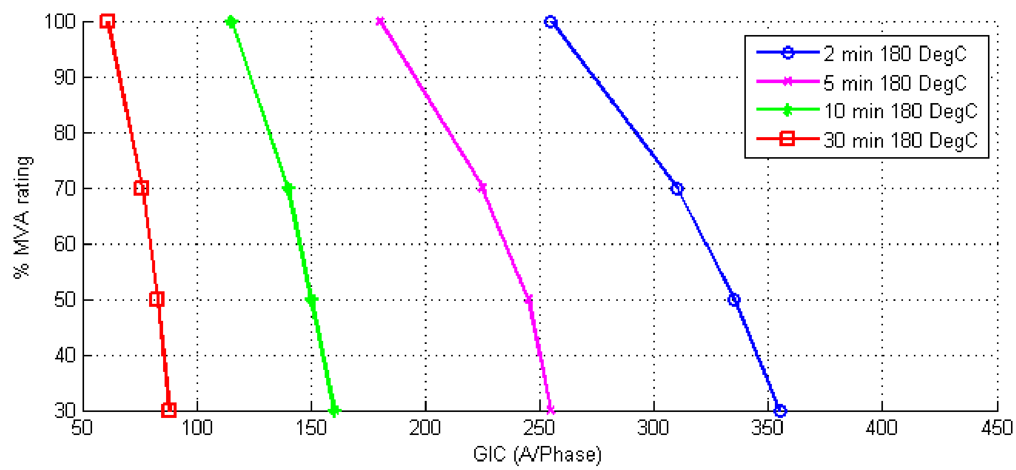

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

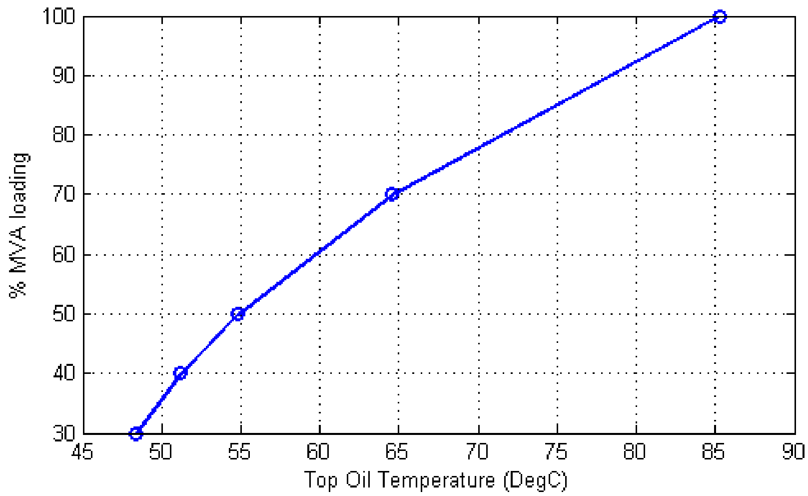

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

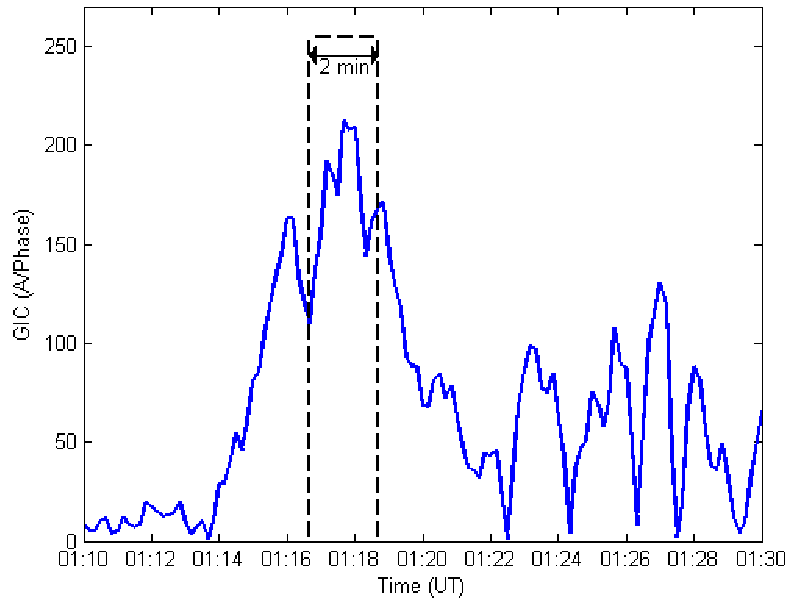

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

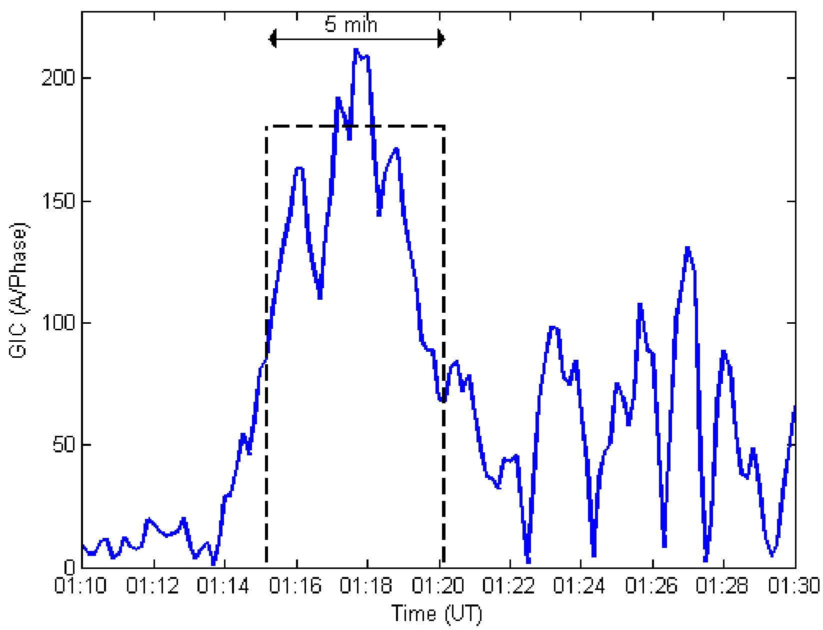

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

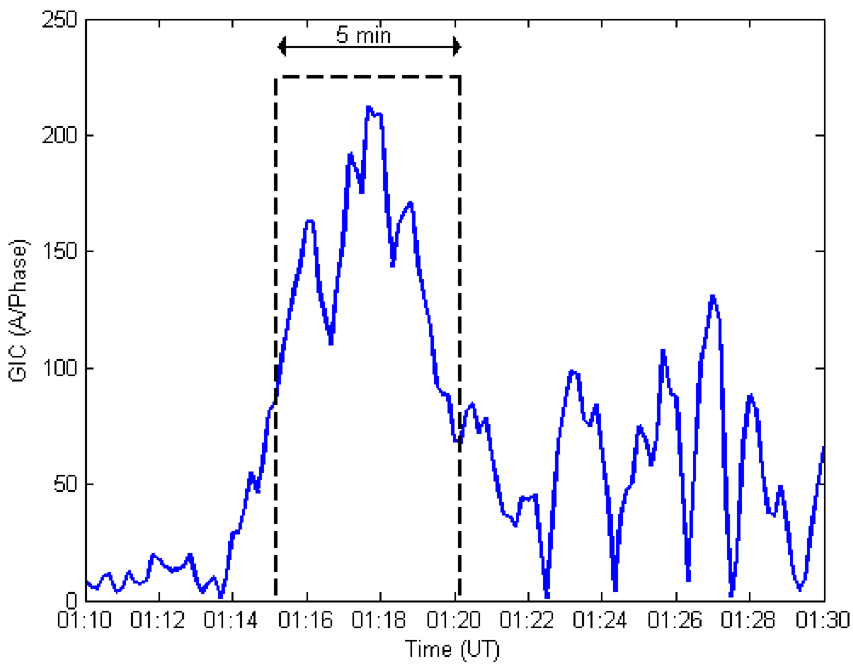

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

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[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

Transformer Thermal Impact Assessment White Paper (Draft)

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved ~~is pending at~~by FERC in ~~Docket No. RM14-1-000~~June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

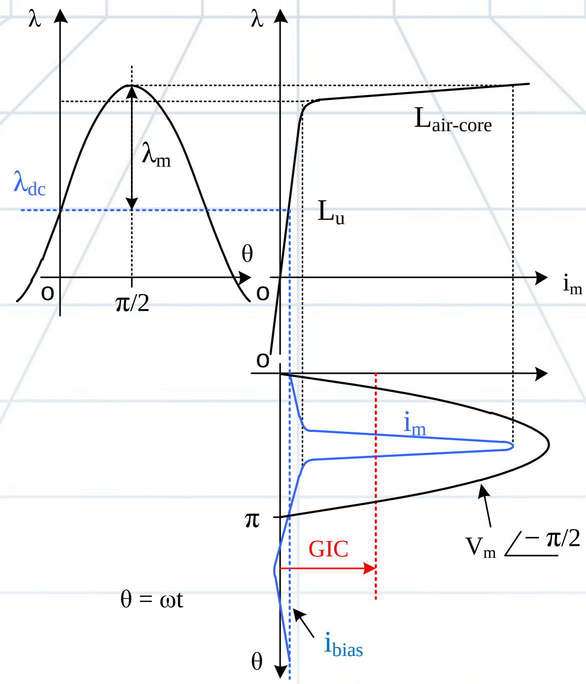

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation, and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2]

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \tag{1}$$

~~where,~~

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

There are two different ways to carry out a detailed thermal impact screening:

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an ~~fair~~ amount of engineering judgment is necessary to ascertain ~~what~~ which portion of a GIC waveshape is equivalent to, for ~~instance~~example, 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~~ must be developed for every transformer design and vintage.

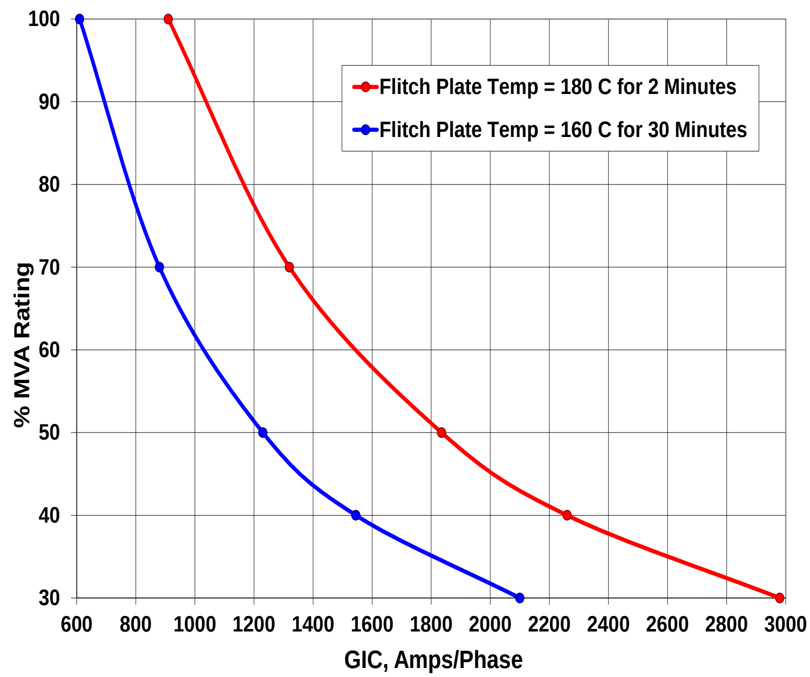

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in

[1] Technical details of this methodology can be found in [4].

Figure 3. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std. C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

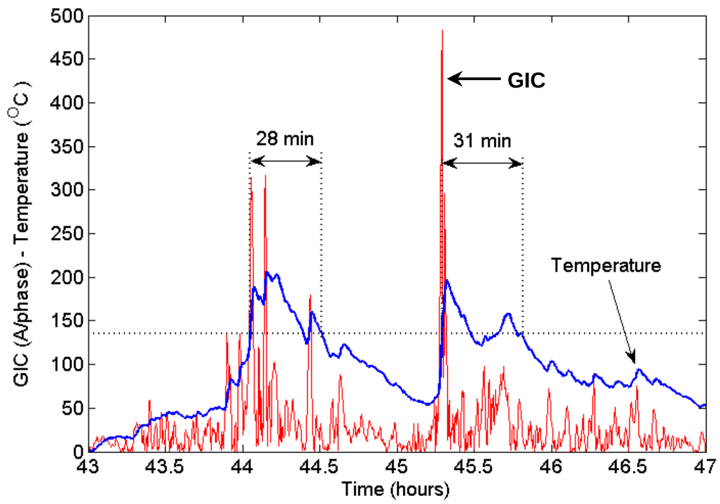

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. -Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase/V/km) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km.

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. -When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already ~~taken into~~ accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$- results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:~~,~~

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

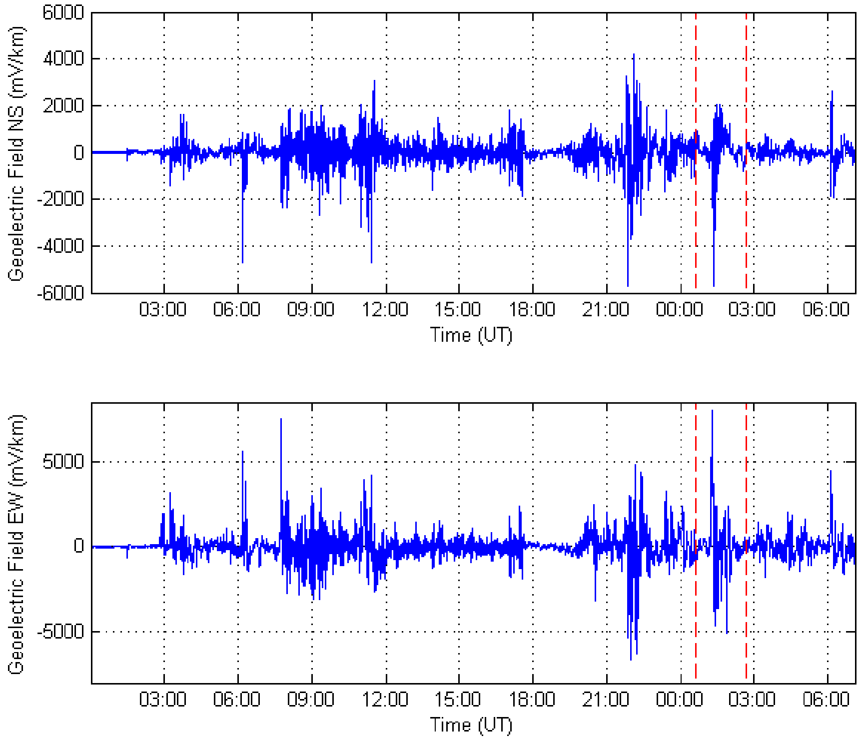

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming α=1 and β=1 (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

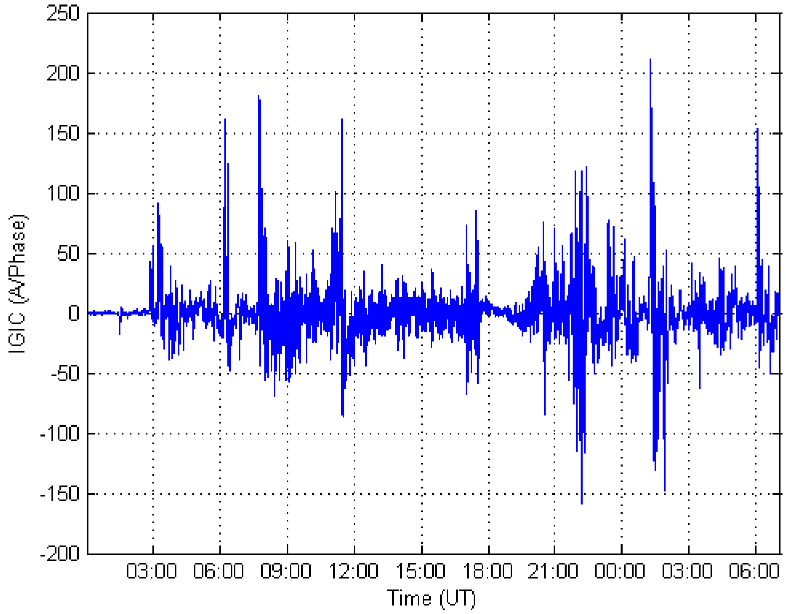

Figure 5: Calculated GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

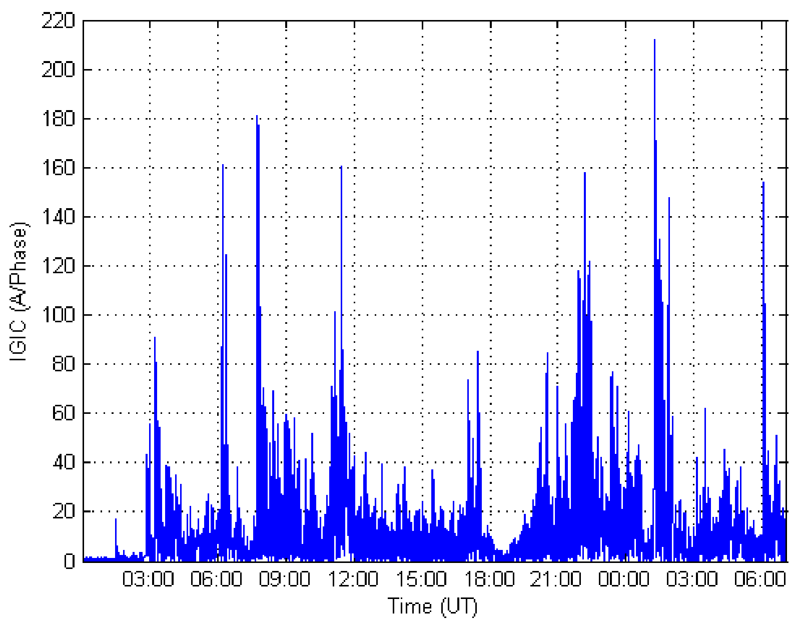

Figure 6: Calculated Magnitude of GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer’s capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: ~~-~~1) measurements; 2) manufacturer’s calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

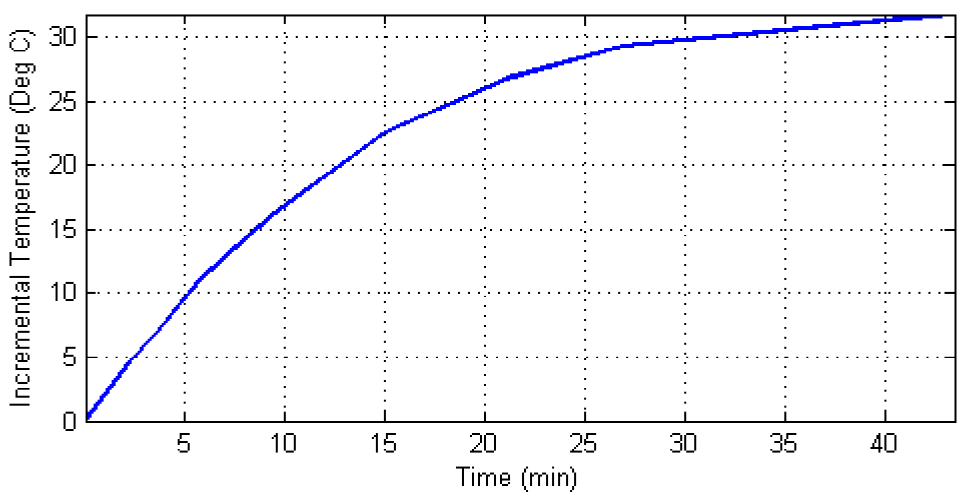

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] ~~The~~ H~~h~~eating of ~~the~~ bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

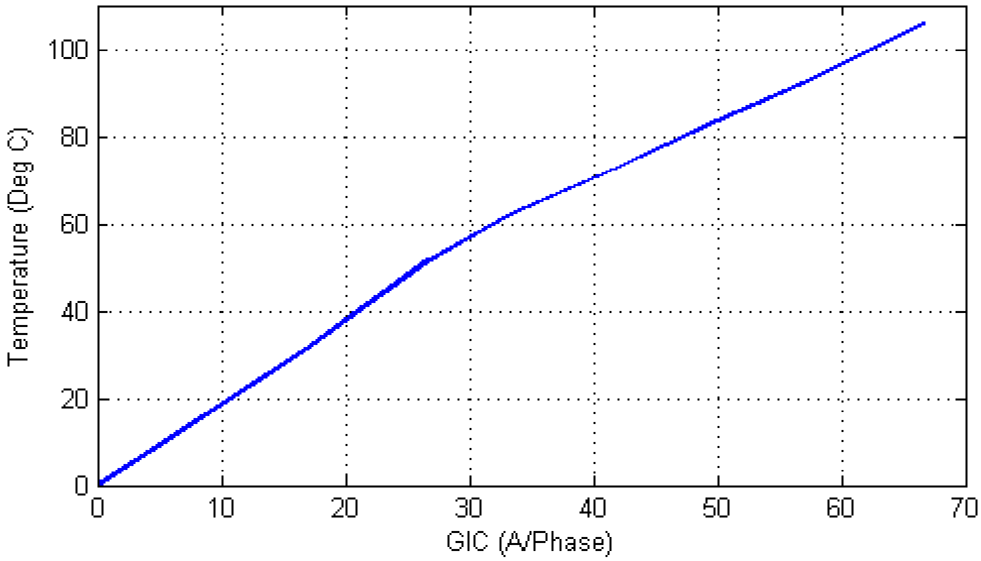

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. -**Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

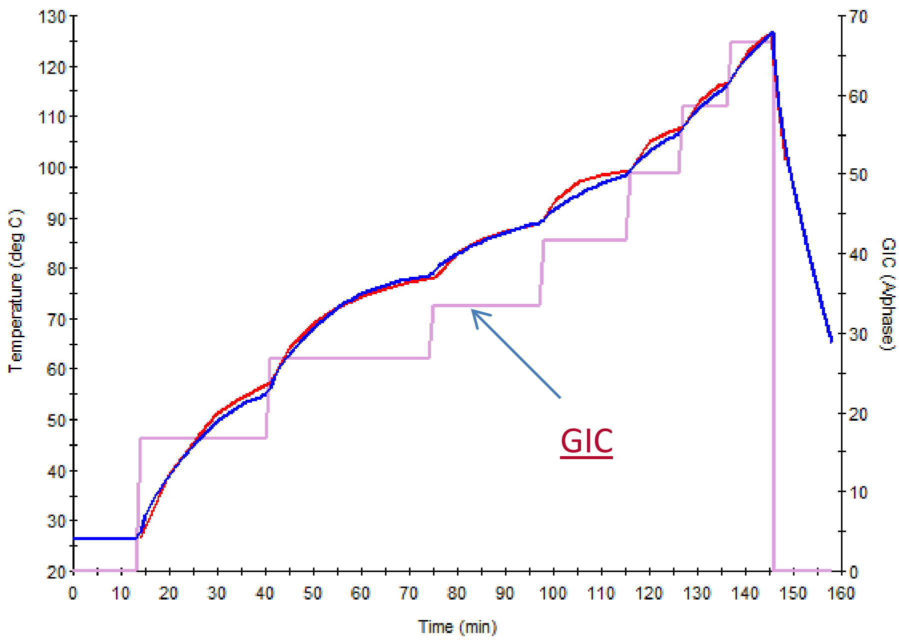

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). ~~Magenta trace is Tthe~~ Iinjected current is represented by the magenta trace.

~~In order~~ T~~t~~o obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure ~~9~~ 10 ~~shows~~ illustrates the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure ~~10~~ 11** ~~shows~~ illustrates a close-up view of the peak transformer temperatures calculated in this example.

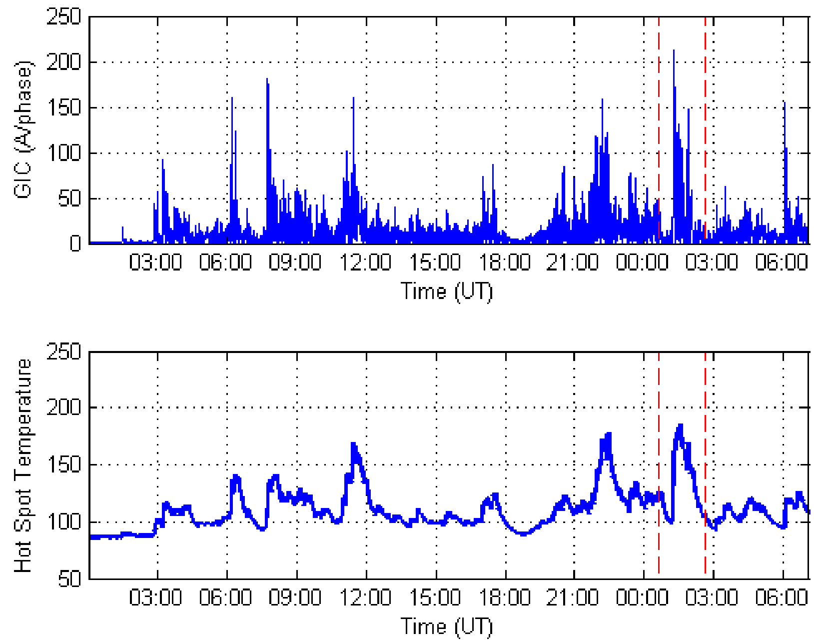

Figure ~~9~~10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

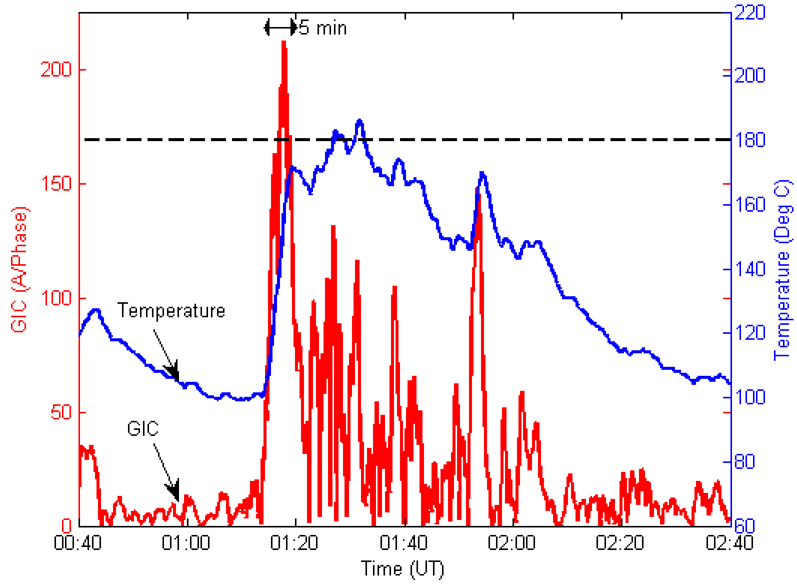

Figure ~~10~~11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std. C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure** ~~10~~ 11 shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure** ~~11~~12).

If a conservative threshold of 160°C were ~~to be~~ used to ~~take into~~ account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

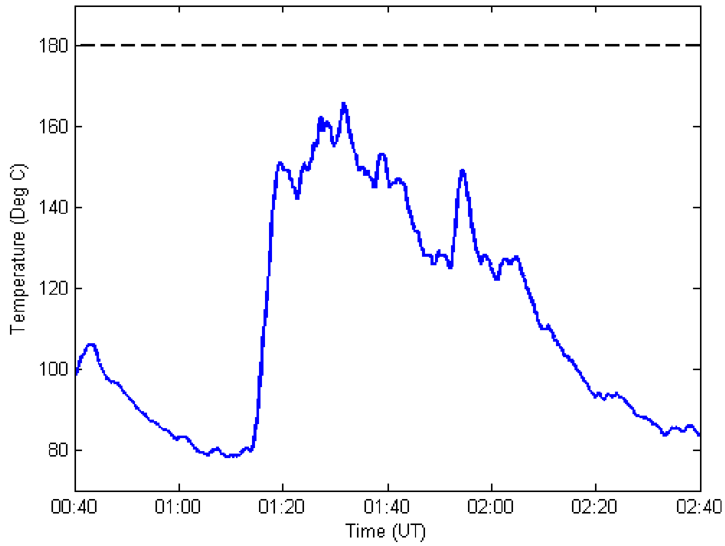

Figure ~~11~~12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure ~~12~~13**. To ~~be consistent~~maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures ~~8~~ 7** and **~~9~~8**, and the simplified loading curve shown in **Figure ~~14~~ 13** (calculated using formulas from IEEE Std. C57.91).

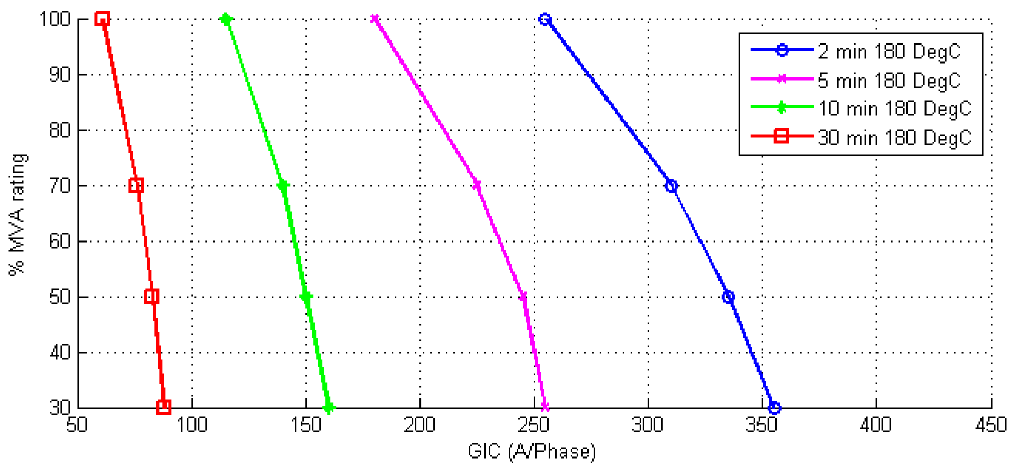

Figure ~~12~~13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

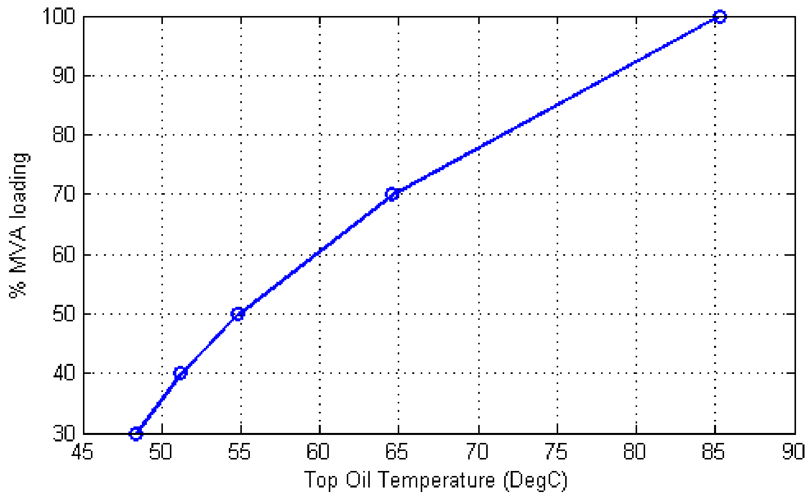

Figure ~~13~~14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure** ~~14~~ 15 shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure** ~~12~~13. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure** ~~15~~16. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

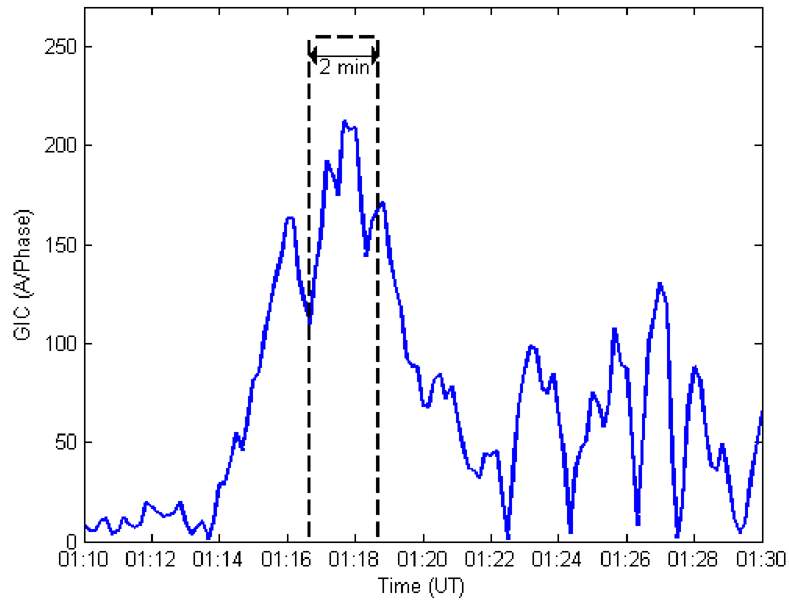

Figure ~~14~~15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

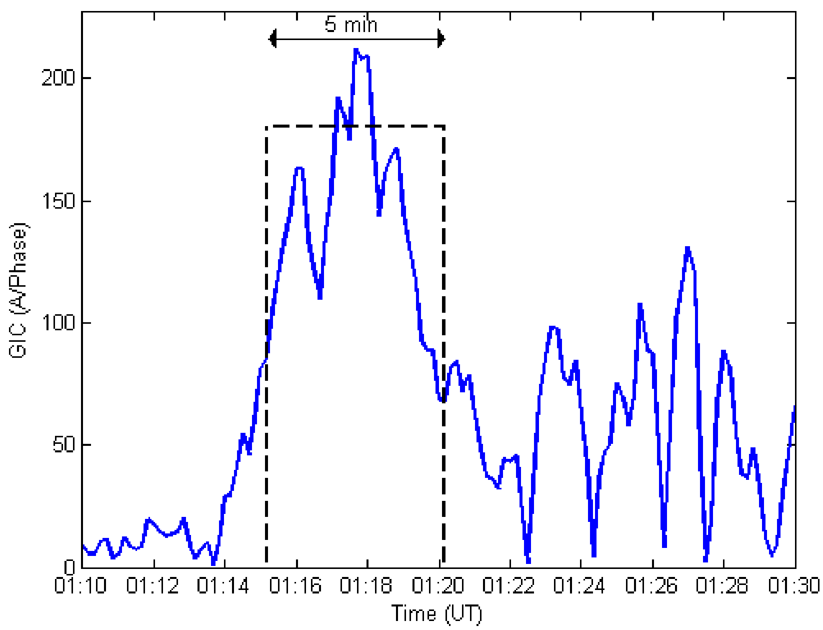

Figure ~~15~~16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), ~~allowances have to be made in terms of~~ prior hot spot heating must be accounted for. From these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure ~~12~~ 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure ~~16~~17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were ~~to be~~ used to ~~take into~~ account for the age and condition of the transformer, then a new set of capability curves would be required.

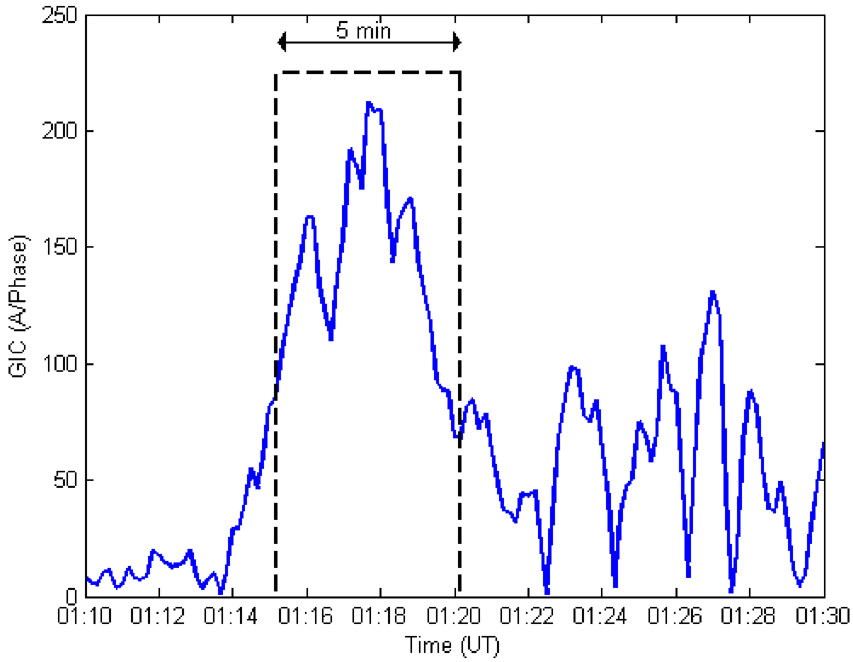

Figure ~~16~~17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. -"Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] Lahtinen, Matti. -Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 15 Amperes per phase is a conservative screening criterion. A list of reference materials is included herein.

Justification

Heating of the winding and other structural parts can occur in power transformers during a GMD event. These thermal impacts are dependent on the thermal time constants of the transformer. The following analysis of tested transformers [*See* References 1-4] assumes a long-duration 15 Amperes per phase neutral current in the transformer, which is a conservative assumption.

From IEEE Std. C57.91 2011 [5], the suggested long-time emergency loading metallic hot spot temperature is 160°C as shown in **Table 1**. The top oil temperature limit for the same operating conditions is 110 (ambient + full load). This suggests that a 50°C temperature increase for three hours for metallic part hot spot heating is a conservative and safe incremental temperature. The highest incremental asymptotic hot spot temperatures measured in [1-4] are shown in Figures 1 to 4.

TABLE 1:Excerpt from Maximum Temperature Limits Suggested in IEEE C57-91 2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

Figure 1 corresponds to the thermal asymptotic response of the tie plate of a 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [1]. The asymptotic behavior for GIC values above 5 Amperes per phase has been linearly extrapolated. Although such extrapolation is probably very conservative for GIC values above 40 Amperes per phase it is consistent with the thermal behavior of metallic hot spots demonstrated in other measurements (e.g., [2], [3]). The incremental asymptotic temperature for 15 Amperes per phase is 46.8 °C.

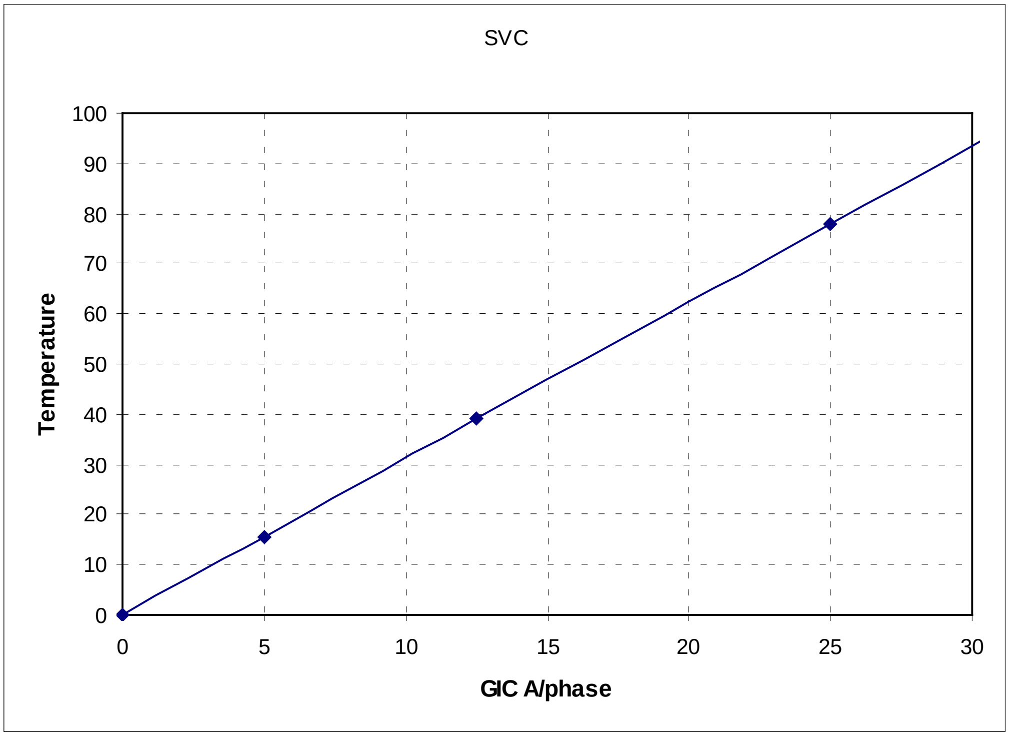

Figure 1: Asymptotic thermal response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer.

Figure 2 corresponds to the thermal asymptotic response of tie plate of a 735 kV 370 MVA single-phase core-type autotransformer [2]. The asymptotic response depicted in **Figure 2** is a combination of measurements and calculated values. In this case, 12.5 Amperes per phase caused an increase of 36 °C while 25 Amperes per phase caused an increase of 89 °C. Interpolation between these two points gives an increase of 47 °C at 15 Amperes per phase. The highest current injected into this transformer is reported as 75 Amperes per phase for 1 hour. The transformer was energized from the 735 kV terminals and weak-source uncertainties normally seen in factory floor tests [4] would have been low in these tests.

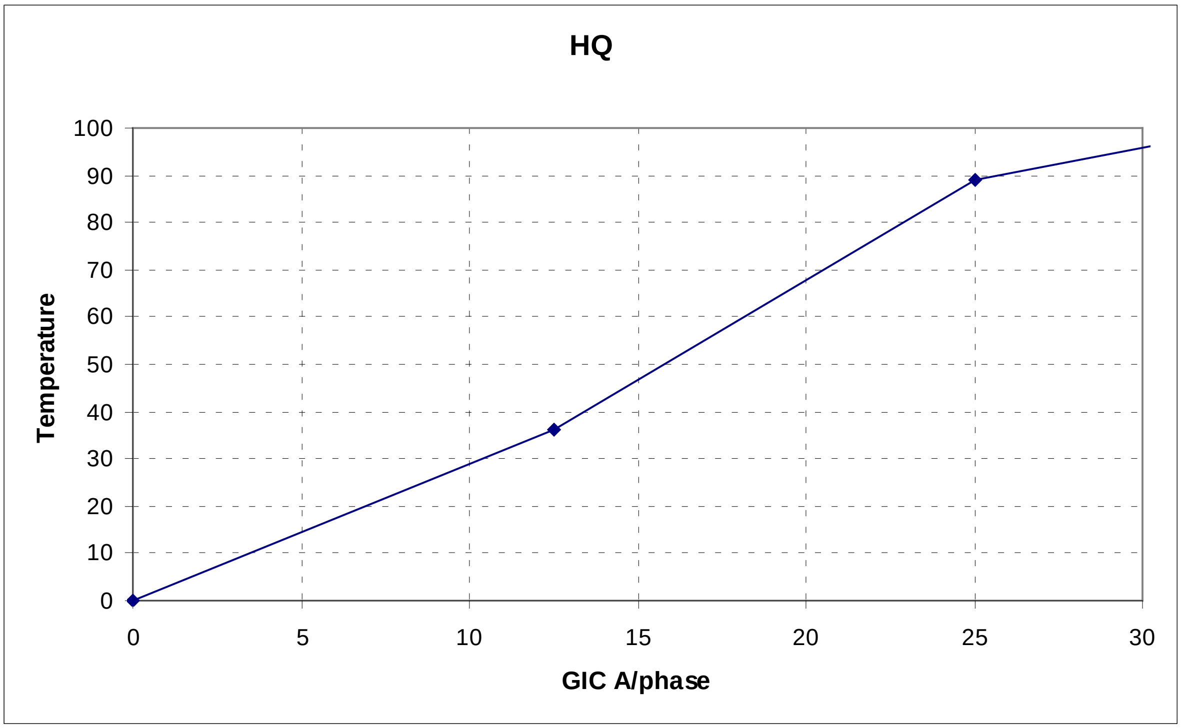

Figure 2: Asymptotic thermal response of the tie plate of a 735 kV 370 MVA single-phase core-type autotransformer.

Figure 3 corresponds to the thermal asymptotic response of the top and bottom clamps of a 400 kV 400 MVA five-leg core-type fully-wound transformer [3]. Hot spot temperature of 34 °C for 15 Amperes per phase occurred at the Flitch plate. Highest current injected into this transformer is reported as 66.67 Amperes per phase for approximately 10 minutes. The transformer was energized from the 400 kV terminals and weak-source uncertainties would have been low.

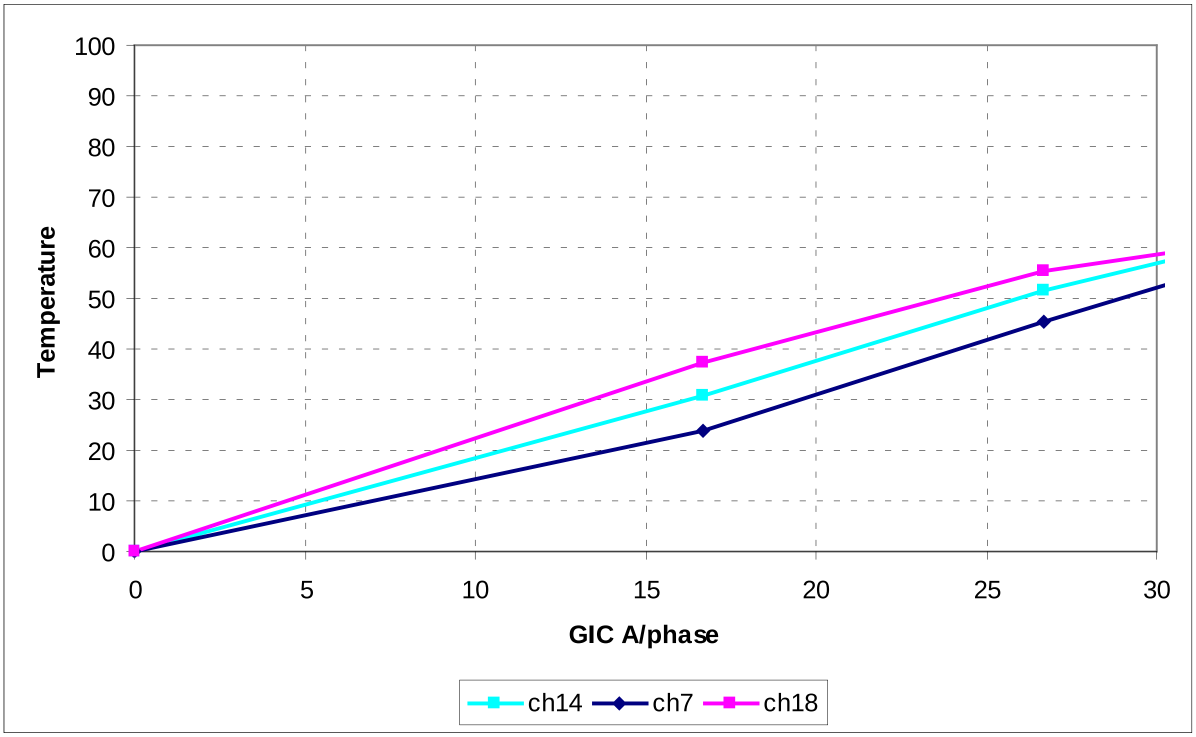

Figure 3: Asymptotic thermal responses of the bottom and top yoke clamps (ch14 and ch7), and Flitch plate (ch18) of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

Figure 4 shows tests carried out in a factory floor of a fully instrumented 400 kV 400 MVA single-phase core-type autotransformer. Tie-plate hot spot temperature of 46 °C for 15 Amperes per phase was measured. The weak ac supply is an issue in these tests and the actual asymptotic response for lower values of GIC above 10 A/phase is probably higher than measured. However at these relatively low GIC values, saturation of structural parts is not a dominant issue.

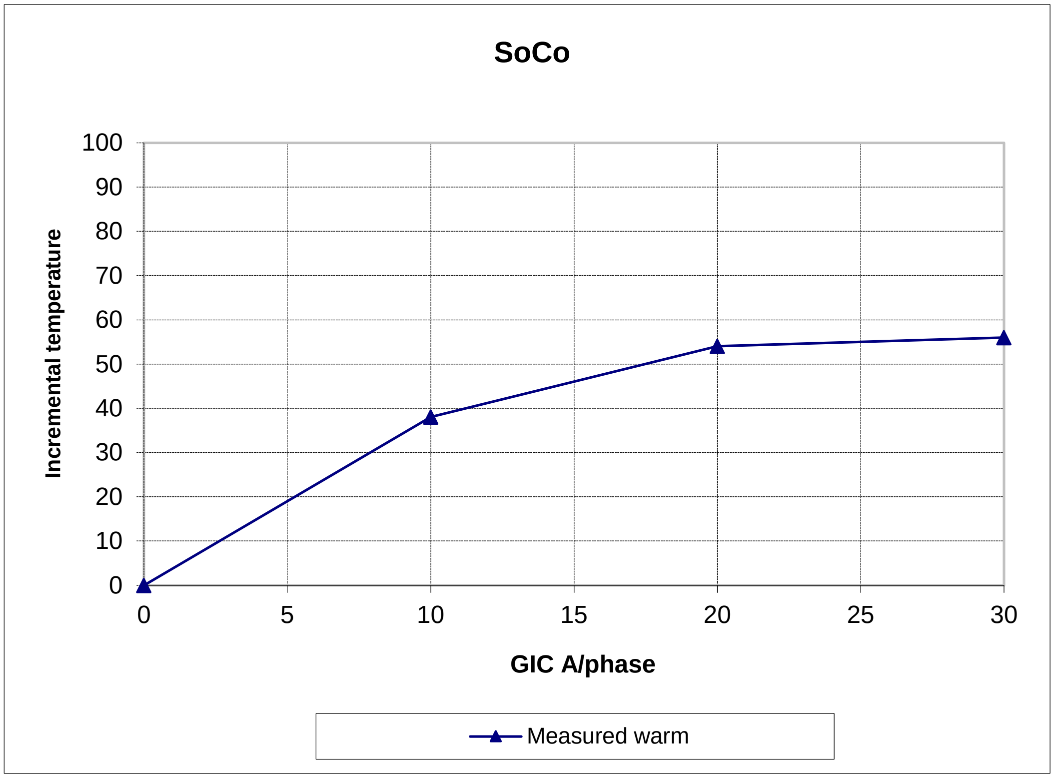

Figure 4: Asymptotic thermal responses of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

In all of the test results presented, an effective GIC value of 15 Amperes per phase resulted in a temperature increase of less than 50°C. These results strongly support use of 15 Amperes per phase as a conservative criterion for determining which applicable transformers require assessment using more detailed methods like those described in the Transformer Thermal Impact Assessment white paper [6]. Furthermore there is significant margin in the assumption of an injected dc current of 15 Amperes per phase for three hours (as opposed to GIC time series information). This conservative approach provides ample margin to account for any uncertainty resulting from the limited number of tested transformers.

References

[1] Marti, L., Rezaei-Zare, A., Narang, A. , "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery, ,* vol.28, no.1, pp.320-327, Jan. 2013

[2] Picher, R.; Bolduc, L.; Pham, V.Q., "Study of the Acceptable DC Current Limit in Core-Form Power Transformer," *Power Engineering Review, IEEE* , vol.17, no.1, pp.50,51, January 1997

[3] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[4] NERC GMD TF Presentation, Atlanta, Nov. 2013 http://www.nerc.com/comm/pc/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMDTF%20Transformer%20Session.pdf?Mobile=1&Source=%2Fcomm%2Fpc%2F_layouts%2Fmobile%2Fdispform.aspx%3FList%3Da84e3238-8456-4456-9ca7-fe46bebd7392%26View%3De8c6afc7-3ec9-4e4c-89d7-ef43bd2911d9%26ID%3D39%26CurrentPage%3D1

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[6] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Violation Risk Factor and Violation Severity Level Justifications

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk

Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities

- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications – TPL-007-1, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Low is consistent with approved TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-1 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A Violation Risk Factor of Low is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing GMD studies, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System under conditions of a GMD event.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its

			Transmission Planners, failed to identify individual or joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R7. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved TPL-001-4 Requirement R1 which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-1, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to maintain models of the responsible entity's planning area for performing GMD studies could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity did not maintain either System models	The responsible entity did not maintain both System models

Proposed VSLs – TPL-007-1, R2			
		or GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).	and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to models for GMD Vulnerability Assessments. Approved TPL-001-4 Requirement R1 requires entities to maintain System models for Planning Assessments and has multiple subparts to form the basis for a graduated VRF. However, the System model for GMD Vulnerability Assessment will have most elements in common with the System model used for Planning Assessments in TPL-001-4. System models for GMD Vulnerability Assessment are distinguished primarily in that they account for reactive power losses due to GIC. Therefore, the subparts from approved TPL-001-4 Requirement R1 were not duplicated in proposed TPL-007-1 Requirement R2 and the VSL was not separated into further degrees of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-1, R2	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-1 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event; these limits may be different from those determined in approved TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-1, R3			
			System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.

VSL Justifications – TPL-007-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R5. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-1, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the BES meets performance criteria. Proposed TPL-007-1 Requirement R3 requires responsible entities to complete a GMD Vulnerability Assessment to ensure the system meets performance criteria during a benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a GMD Vulnerability Assessment but it was more	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy

Proposed VSLs – TPL-007-1, R4			
than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	of elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	three of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

VSL Justifications – TPL-007-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R4	
Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

VSL Justifications – TPL-007-1, R4	
Cumulative Number of Violations	

VRF Justifications – TPL-007-1, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A Violation Risk Factor of Medium is also consistent with approved IRO-010-1a Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-1 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R5			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R5			
N/A	N/A	The responsible entity failed to provide one of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.	The responsible entity failed to provide two of the elements listed in Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer; OR The responsible entity did not provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer.

VSL Justifications – TPL-007-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved MOD-032-1, Requirement R2 and IRO-010-1a, Requirement R3, which also have a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R5	
Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

VSL Justifications – TPL-007-1, R5	
Cumulative Number of Violations	

VRF Justifications – TPL-007-1, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-1 Requirement R6 requires responsible entities to conduct a thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a thermal impact assessment for 5% or less or one	The responsible entity failed to conduct a thermal impact assessment for more than 5% up	The responsible entity failed to conduct a thermal impact assessment for more than 10%	The responsible entity failed to conduct a thermal impact assessment for more than 15%

Proposed VSLs – TPL-007-1, R6			
of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24-calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of the required elements as listed in	to (and including) 10% or two of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include two of the required	up to (and including) 15% or three of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include three of the required	or more than three of its solely owned and jointly owned applicable power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include four of the required elements as listed in Requirement R6 parts 6.1 through 6.4.

Proposed VSLs – TPL-007-1, R6			
Requirement R6 parts 6.1 through 6.4.	elements as listed in Requirement R6 parts 6.1 through 6.4.	elements as listed in Requirement R6 parts 6.1 through 6.4.	

VSL Justifications – TPL-007-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved FAC-008-3, Requirement R6. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-1, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-1 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While approved TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-1 has split the requirements for performing a GMD Vulnerability Assessment and development of the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Standards Announcement Reminder

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Additional Ballot Now Open through October 10, 2014

Now Available

An additional ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Friday, October 10, 2014**.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post them for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson,
Standards Developer, or at 404-446-2560.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Formal Comment Period Now Open through October 10, 2014

Now Available

A 45-day formal comment period for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern on Friday, October 10, 2014**.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 1-10, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Formal Comment Period Now Open through October 10, 2014

Now Available

A 45-day formal comment period for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern on Friday, October 10, 2014**.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 1-10, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, October 10, 2014**.

The standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results	Non-Binding Poll Results
Quorum /Approval	Quorum/Supportive Opinions
82.93% / 57.95%	81.69% / 59.63%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period to determine the next steps.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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Ballot Results	
Ballot Name:	Project 2013-03 GMD TPL-007-1_Additional_Ballot
Ballot Period:	10/1/2014 - 10/10/2014
Ballot Type:	Successive
Total # Votes:	311
Total Ballot Pool:	375
Quorum:	**82.93 % The Quorum has been reached**
Weighted Segment Vote:	57.95 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	107	1	50	0.625	30	0.375	0	11	16
2 - Segment 2	8	0.7	3	0.3	4	0.4	0	0	1
3 - Segment 3	86	1	37	0.552	30	0.448	0	6	13
4 - Segment 4	24	1	13	0.722	5	0.278	0	4	2
5 - Segment 5	79	1	32	0.582	23	0.418	0	6	18
6 - Segment 6	54	1	27	0.659	14	0.341	0	4	9
7 - Segment 7	3	0.1	0	0	1	0.1	0	0	2
8 - Segment 8	5	0.4	1	0.1	3	0.3	0	0	1
9 - Segment 9	2	0.1	0	0	1	0.1	0	0	1

10 - Segment 10	7	0.5	4	0.4	1	0.1	0	1	1
Totals	**375**	**6.8**	**167**	**3.94**	**112**	**2.86**	**0**	**32**	**64**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support MRO NSRF comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas E. Foltz, American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD's Mahmood Safi)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Abstain	

1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments Submitted by Maryclaire Yatsko)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES & NRECA)
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Indiana Gas & Electric)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Abstain	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		

1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC and NPCC/RSC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc.)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall, CSU)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	

3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc.)
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	COMMENT RECEIVED
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MEC Comments)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Abstain	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support MRO NSRF comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
				SUPPORTS

3	Ocala Utility Services	Randy Hahn	Negative	THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc.)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Submitted by Phil Kleckley)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	

4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments Submitted by Maryclaire Yatsko)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski we energies)
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	

5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC comments submitted by Alshare Hughes)
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nevada Power Co.	Richard Salgo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mid American Energy Co.)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		

5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments submitted by Maryclaire Yatsko)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Southern Indiana Gas and Electric Co.	Rob Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support third party comments by Southern Indiana Gas & Electric)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (AEP - Tom Foltz)
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	COMMENT

				RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Maryclaire Yatsko on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern

				Indiana Gas & Electric Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
7	Luminant Mining Company LLC	Stewart Rake	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Co LLC)
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz		
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Non-Binding Poll Results

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-03 GMD TPL-007-1
Poll Period:	10/1/2014 - 10/10/2014
Total # Opinions:	281
Total Ballot Pool:	344
Summary Results:	81.69% of those who registered to participate provided an opinion or an abstention; 59.63% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon		
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner		

1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD's Mahmood Safi)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registered Affiliates)

1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments Submitted by Maryclaire Yatsko)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES& NRECA)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Abstain	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	

1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Kaleb Brimhall, CSU)
3	ComEd	John Bee		
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	COMMENT RECEIVED
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	

3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MEC Comments)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Abstain	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support MRO NSRF comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Submitted by Phil Kleckley)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments Submitted by Maryclaire Yatsko)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb

				Kedrowski we energies)
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorad Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	

5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC GMD Task Force)
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC comments)
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		

5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments submitted by Maryclaire Yatsko)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson		
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	

6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Maryclaire Yatsko on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
7	Luminant Mining Company LLC	Stewart Rake	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Co LLC)
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz		
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (58 Responses)
Name (35 Responses)
Organization (35 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Question 1 (49 Responses)
Question 1 Comments (58 Responses)
Question 2 (47 Responses)
Question 2 Comments (58 Responses)
Question 3 (40 Responses)
Question 3 Comments (58 Responses)
Question 4 (52 Responses)
Question 4 Comments (58 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type 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 and appropriate. On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads: “Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network

model.” Suggest adding the following paragraph afterwards: “Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model.” This comment was submitted during the last comment period.
Yes
Yes
The requirements and measures should be revised to allow Planning Coordinators to generally utilize consensus processes and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, the modeling data itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since those standards deal with load flow, stability, and short circuit data. Recommend that MOD-32 requirements R2 and R3 be added as requirements in the beginning of the GMD standard, but in R2 substitute the word “GMD” for “steady-state, dynamics, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. The Applicability section would have to be revised to include the additional entities. Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read “…wye-grounded winding with voltage terminals operated at 200kV or higher”. In Requirement R4 sub-Part 4.1.1. “System On-Peak Load” should be re-stated as “System On-Peak Load with the largest VAR consumption”. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x α x β (in V/km). This indicates that the driving electrical field is in the Earth, and

not in the transmission wires. The wires do not create some kind of “antenna” effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections. This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.
Individual
Dr. Gabriel Recchia
University of Memphis
No
I would support a version of TPL-007-1 for which the statistical analyses were recomputed to take the considerations I mention in my responses to Question 4 into account, for which the numbers in TPL-007-1 Attachment 1 were adjusted accordingly, and for which the standards were adjusted to be appropriate given the new values.
Yes
In Appendix I of the Benchmark Geomagnetic Disturbance Event Description, I was concerned to see a decision to compute geoelectric field amplitude statistics that are averaged over a wide area. Appendix I of the Benchmark GMD Event Description currently states "The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales... Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below" (p. 9). However, to prepare for GMDs via the benchmark's current method (averaging over a square area of approximately 500 km in width) is similar to anticipating a 7.0 earthquake somewhere along the California coast, but preparing only for the average expected impact. Because the earthquake is only expected in one particular location, the average impact across the entire coast will be miniscule; if all

locations prepared only for the average impact, some would be woefully underprepared. In fact, the assumption is far worse than this earthquake analogy implies, because local failures in interconnected power systems can and do produce wide-area effects, as seen during the 1989 Hydro-Quebec blackout and the Northeast blackout of 2003*. Thus, analyses based on localized spatial scale estimates are precisely what is relevant, not wide-area spatial averages. I am also concerned that the extreme value analysis described does not take into account the fact that extreme space weather events follow a power law distribution (Lu & Hamilton, 1991; Riley, 2012). As stated by Riley (2012), "It is worth emphasizing that power laws fall off much less rapidly than the more often encountered Gaussian distribution. Thus, extreme events following a power law tend to occur far more frequently than we might intuitively expect" (see also Newman, 2005). Therefore it is likely that the analysis substantially underestimates the risk of high geoelectric field amplitudes. *Though not related to GMDs, the Northeast blackout of 2003 is nonetheless a good example of a local failure having wide-area effects. Lu, E. T., and R. J. Hamilton (1991), Avalanches and the distribution of solar flares, Astrophys. J., 380, L89–L92. Newman, M. (2005), Power laws, Pareto distributions and Zipf's law, Contemp. Phys., 46, 323–351. Riley, P. (2012), On the probability of occurrence of extreme space weather events, Space Weather, 10, S02012, doi:10.1029/2011SW000734.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
No
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. The drafting team continues to state that it is the responsibility of the owner to mitigate. 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 or the drafting team must clearly communicate how they envision the coordination between the PC/TP and the TO/GO occurring. TOs and GOs need to be involved in the development of the Corrective Action Plans that they will required to execute. The standard should require the PC to set up a stakeholder process with TOs and GOs related to these corrective action plans. The stakeholder process would take into account considerations such as scope of corrective action plans, schedules, market impacts, etc.
Yes
Yes
Yes
AEP remains concerned about the availability of the generic screening models. While the drafting team continues to publicize that the use of these models is an option for meeting the TO/GO requirements in R6, the drafting team has also stated that the development of the models is outside of their scope. In order to address uncertainty regarding these generic thermal models, AEP suggests that NERC commit to making industry-wide generic thermal models available as soon as possible, but no more than 18 months after NERC BOT approval of TPL-007-1. AEP supports the overall direction of this project, and envisions voting in the affirmative if the concerns provided in our response are sufficiently addressed in future revisions of TPL-007-1.
Individual
Thomas Lyons
Owensboro Municipal Utilities
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Group
Dominion
Louis Slade
Yes

Yes
Yes
No
Individual
Terry Volkmann
Volkmann COnsulting
No
There is no technical justification to add an additional year to the process to an imminent problem.
No
There is no technical justification to add an additional year to the process to an imminent problem
Yes
Yes
The technical justification for spatial average of the 8V/km has not been adequately vetted among peers, the electric utility has not expertise in this average. In addition the SDT has not justified limiting the peak E-field area to only 100km. If it is 500km this is a huge area of the BES to allow a voltage collapse any outage.
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
No
(1) Seminole is confused as to whether the CP-3 value has been finalized by USGS or not, as USGS's website does not reflect the CP-3 value represented in the latest ballot. If the ground conductivity value for the Florida Peninsula, CP-3, is not final, i.e., USGS is still developing and researching the value, then the drafting team should delay vote on the Standard or allow for successive balloting on the final CP-3 value when USGS finalizes its value. Seminole does not believe the NERC Standards Process Manual allows for revisions to the CP-3 value after the Standard has been approved without re-opening the balloting. (2) Seminole is aware that a CEAP is not required to be performed, however, Seminole believes a CEAP is justified in this particular circumstance.
No
See Comments for #1 above and previous ballot Comments.

Individual
Bill Daugherty
Concerned citizen
No
The selection of the March 13-14 1989 GMD (Hydro Quebec) and the October 29-31 2003 Halloween events to define the 100 year GMD standards ignores a substantial body of work by researchers such as Bruce Tsurutani (NASA) and Daniel Baker (University of Colorado). NERC has chosen to define the 100 year GMD based solely on GMD events that were measured when CMEs actually hit the Earth in the 1980 to 2013 time frame. This ignores the work done by Tsurutani, Baker, and others that have quantified the magnitude of both pre 1980 events as well as events like the July 2013 event that was directed away from the Earth. The 1989 GMD was not all that strong when viewed on a historical basis, and the 2003 Halloween event, while a X17.2, resulted in a greatly dampened measured effect on the Earth's magnetic field since the magnetic component was pointing northward when it hit the Earth. Had it been pointing southward, the measured effect would have been greatly amplified. This 100 year GMD standard should not be allowed to be finalized without incorporating the findings and recommendations of papers like: Baker, D. N., X. Li, A. Pulkkinen, C. M. Ngwira, M. L. Mays, A. B. Galvin, and K. D. C. Simunac (2013), A major solar eruptive event in July 2012: Defining extreme space weather scenarios, Space Weather, 11, 585–591, doi:10.1002/swe.20097. and Tsurutani, B. T., and G. S. Lakhina (2014), An extreme coronal mass ejection and consequences for the magnetosphere and Earth, Geophys. Res. Lett., 41, doi:10.1002/2013GL058825 NERC has greatly underestimated the true magnitude of the 100 year threat to the electric grid from solar storms. This must be addressed before these standards are finalized.
No
Given the studies that I referenced in my response to Question 1, four years may be too long.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co.
Yes
Yes
Yes
Yes

For requirement 6 transformer assessment, we have a concern that the data required from the manufacturer of the transformer will not be available, especially for older units where the transformer manufacturer is no longer in business. From the 9/10/14 webinar, it is understood that screening models are in development, but there is no guarantee that they will be available to complete the assessment. Since we currently do not have any means at this time to complete this standard requirement, we will have to vote against approval of this standard.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
1.) Requirement 4.3 should have to be shared upon request only. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
No
1.) As many companies are going to be required to buy software and train for the specific modeling being required we recommend that this requirement have a 24 month implementation period. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Yes
We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Yes
Thank you for all of your work on this – this is not an easy one! We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. On some of even the most recent calls there still appears to be some lack of understanding as technical questions are asked. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. We recommend a pilot program. 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. If we pilot the process and shorten the implementation period then the final implementation of the solution could be the same with a much better effect. Please ask the question on the pilot even if the standard must move forward as is. Having the regions and NERC work through the process quickly with a few entities would still be very beneficial. Then all the other companies do not have to repeat the same mistakes to get where we really need to be. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Individual
John Merrell

Tacoma Power
Yes
Yes
Yes
No
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
No
Group
FirstEnergy Corp.
Richard Hoag
Yes
Yes
Increase from 4 to 5 years is an improvement
Yes
No
Individual
David Jendras
Ameren
No
We still strongly feel that a GMD event of 4-5 times the magnitude of the 1989 Quebec event as the basis for the 1 in 100 year storm is too severe, given the few “high magnitude” events that have occurred over the last 21 years, and therefore we believe that the

requirements to provide mitigation for these extreme GMD events are not supported. On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Minnesota as for Louisiana, while conservative, we believe would be absurd. Consideration with respect to unique geographical differences must be maintained among the functional entities to whom this standard would be applicable, particularly for PC's and their associated TP/TO entities.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
What is the estimated cost impact to entities for this activity, and what is the estimated marginal improvement in system reliability? We have heard from peers that the data requirements for a large system would take approximately 1 man-year to develop, and the source for this information is from a utility that has performed this activity per the draft standard. We are concerned given this significant investment in time and engineering resources, is there truly a need for a continent-wide standard when only select areas of the continent need to be concerned with GMD evaluation and mitigation? In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. We understand from representatives on the IEEE Transformer Committee that there are concerns that the 15 A threshold identified in the GIC standard is too low. We understand that the IEEE will be making a case to raise this threshold because the likelihood of transformer damage is small at that level of DC current (15 A) for the expected transient durations.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
The NSRF agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Yes

1. The NSRF agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. We suggest the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement: The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.
No
• The NSRF suggest the SDT change the VSL row for Requirement R6 to match the words in the standard. Suggestion: "The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months…" • The NSRF suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row. Suggestion: "The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Yes
• Page 9, Table 1 –Steady State Planning Events The NSRF suggest that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, we suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. • Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion: 4.2. Facilities: 4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. 4.2.1 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
Individual
Eric Bakie
Idaho Power
Yes
Yes
Yes

Yes
Idaho Power System Planning comments that additional clarity needs added to Table 1 regarding the GMD Event with Outages Category. It is unclear if planners have to include contingency conditions during a GMD event in the vulnerability assessment. If intent of the SDT is to require contingency analysis during a GMD Event to assess system performance; the required contingency categories (i.e. A or N-0, B or N-1, C or N-2) should be clearly identified in Table 1.
Group
SERC Planning Standards Subcommittee
David Greene
No
On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Louisiana as for Minnesota, while conservative, would be absurd. Some sanity in this regard must be maintained among the functional entities to whom this standard would be applicable, particularly for PC's and their associated TP/TO entities.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. 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.
Group
SPP Standards Review Group
Robert Rhodes
No
5. Background – Replace 'Misoperation' with 'Misoperation(s)'. R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 – set the phrase 'as determined in Requirement R1' off with commas. R4 – Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one

year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load. Rationale Box for Requirement R4 – Capitalize ‘On-Peak’ and ‘Off-Peak’. Measure M5 – Insert ‘in the Planning Area’ between ‘Owner’ and ‘that’ in the next to last line of M5. Rationale Box for Requirement R5 – Capitalize ‘Part 5.1’ and ‘Part 5.2’. Likewise, capitalize ‘Part 5.1’ under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section. R6/M6 – Capitalize ‘Part 5.1’. Attachment 1 – We thank the drafting team for providing more clarity in the determination of the β scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Yes
Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requirements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
No
Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs. R5 – Capitalize ‘Parts 5.1 and 5.2’ in the High and Severe VSLs for Requirement R5. R6 – Capitalize ‘Part 5.1’ and ‘Parts 6.1 through 6.4’ in the VSLs for Requirement R6. R7 – Capitalize ‘Parts 7.1 through 7.3’ in the Moderate, High and Severe VSL for Requirment R7.
Yes
We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics – Capitalize ‘Reactive Power’ in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics – Replace ‘Wide Area’ in the 1st line of the 6th bullet under General Characteristics. The lower case ‘wide-area’ was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term ‘Wide Area’ refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don’t believe the usage here is restricted to an RC’s Wide Area view. The lower case’wide-area’ is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude – In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the ‘GIC system model’. In Requirement R2 of the standard a similar reference is made to the ‘GIC System model’ as well as ‘System models’. In the later ‘System’ was capitalized. Should it be capitalized in this reference also? Statistical Considerations – In the 6th line of the 2nd

paragraph under Statistical Considerations, insert ‘the’ between ‘for’ and ‘Carrington’. Statistical Considerations – In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase ‘1 in 100 year’ is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as ‘1-in-100’. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification – In the 3rd line of the 1st paragraph under the Justification section, the phrase ’15 Amperes per phase neutral current’ appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as ’15 Amperes per phase’. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification – In the 2nd paragraph under the Justification section, the term ‘hot spot’ appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn’t. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification – In the 4th line of the Figure 4 paragraph, ’10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Individual
Terry Harbour
MidAmerican Energy Company
Yes
MidAmerican agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Yes
MidAmerican agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. MidAmerican suggests the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the

standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.
No
MidAmerican suggest the SDT change the VSL row for Requirement R6 to match the words in the standard. Suggestion: “The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months…” MidAmerican suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row. Suggestion: “The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Yes
On Page 9, Table 1 – Steady State Planning Events MidAmerican suggests that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion: Add 4.2.2 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. Rationale for R2 Change “accounts for” to “includes” for clarity. Suggestion: The System model specified in Requirement R2 is used in conducting steady state power flow analysis that includes the Reactive Power absorption of transformers due to GIC in the System. Requirement R2 – General Comment Issues may arise in obtaining substation grounding and transformer DC resistance data two buses into neighboring utilities in a timely fashion. MidAmerican suggests some wording be included in Requirement R2 to address this issue, such as direction to share this data with neighboring utilities. Requirement R7 Add a space between R1 and “that”.
Individual
Karin Schweitzer
Texas Reliability Entity
No
1. Requirement R3: Texas Reliability Entity, Inc. (Texas RE) requests the SDT consider and respond to the concern that GMD criteria in the proposed standard for steady state voltage performance is different than the steady state voltage performance criteria in other TPL standards or the SOL methodology. GMD events will typically not be transient in nature so adopting the steady state approach is preferable as it would simplify the studies if the voltage criteria between GMD events and other planning events were the same. 2.

Requirement R7: Texas RE intends to vote negative on this proposed standard solely on the basis that we remain unconvinced that the proposed standard meets the intent of FERC Order 779. Paragraph 79 for the following reasons: (A) Reliance on the definition of Corrective Action Plans (CAP) in the NERC Glossary in lieu of including language in the requirement appears insufficient to address the FERC statement that a Reliability Standard require owners and operators of the BPS to "develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event." While Texas RE agrees that requiring the development of a CAP in Requirement R7 meets part of the FERC directive, R7 falls short as there is no language in the requirement (and therefore the standard) that addresses completion of the CAP. The CAP definition calls for an associated timetable but does not address completion. Coupled with the language in R7.2, that the CAP be reviewed in subsequent GMD Vulnerability Assessments, it is conceivable that a CAP may never get completed as timetables can be revised and extended as long as the deficiency is addressed in future Vulnerability Assessments. Without a completion requirement, a demonstrable reliability risk to the BES may persist in perpetuity. Texas RE recommends the SDT revise Requirement R7.2 as follows: "Be completed prior to the next GMD Vulnerability Assessments unless granted an extension by the Planning Coordinator." (B) The language in R7.1 does not appear to adequately address the FERC statement that "Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." While R7.1 lists examples of actions needed to achieve required System performance, it does not expressly restrict a CAP from only including revision of operating procedures or training. In addition, Table 1 language regarding planned system adjustments such as transmission configuration changes and redispatch of generation, or the reliance on manual load shed, seem to contradict the FERC language regarding the limiting plans to considering operational procedures. Texas RE suggests the revising the language of R7.1 as follows: "Corrective actions shall not be limited to considering operational procedures or enhanced training, but may include:" Alternatively, Texas RE suggests the addition of language to the Application Guidelines for Requirement R7 reinforcing FERC's concern that CAPs "must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." 3. Compliance Monitoring Process Section: Evidence Retention Texas RE remains concerned about the evidence retention period of five years for the entire standard. (A) Texas RE reiterates the recommendation that the CAP should be retained until it is completed. The SDT responded to Texas RE's first such recommendation with the following response: "The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not

believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance." With a periodic study period of five years, a CAP may extend significantly beyond the five-year window, especially in cases where equipment replacement or retrofit may be required. A retention period of five years could make it difficult to demonstrate compliance and could potentially place a burden on the entity as they will be asked 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. (B) Texas RE also recommends revising the evidence retention to cover the period of two GMDVAs. The limited evidence retention period has an impact on determination of VSLs, and therefore assessment of penalty. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained.
Yes
Yes
No
Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
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 that is applicable to the transformers to be evaluated. Without the curve(s), the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to affirmative 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.
Group

PPL NERC Registered Affiliates
Brent Ingebrigtson
No
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. The tools available for GOs and TOs to perform the transformer thermal impact assessments of TPL-007-1 requirement 6 are presently inadequate. There are two approaches for such work, as stated on p.4 of NERC's Transformer Thermal Impact Assessment White Paper: use of transformer manufacturer geomagnetically-induced current (GIC) capability curves, or thermal response simulation. We (and probably almost all entities) have no manufacturer GIC data, and the simulation approach requires, "measurements or calculations provided by transformer manufacturers," or, "conservative default values…e.g. those provided in [4]." Reference 4 includes only a few case histories and not widely-applicable transfer functions. Nor does there exist a compendium of, "generic published values," cited on p.9 of the White Paper. Performing thermal response experiments on in-service equipment is out of the question; so enacting TPL-007-1 in its present state would produce a torrent of requests for transformer OEMs to perform studies, this being the only available path forward. We anticipate that each such study would require several days of effort by the OEM and cost several thousand dollars, which would be impractical for addressing every applicable transformer in North America. Generic thermal transfer functions are needed, and the SDT representatives in the 9/3/14 teleconference with the NAGF standards review team agreed, adding that the Transformer Modeling Guide (listed as being "forthcoming" in NERC's Geomagnetic Disturbance Planning Guide of Dec. 2013) will become available prior to the time that GOs and TPs must perform their analyses. We have to base our vote regarding TPL-007-1 on the standard as it presently stands, however. We do not know whether or not the Transformer Modeling Guide will prove suitable, nor is there any guarantee that it will ever be published. We suggest that the standard be resubmitted for voting when all the supporting documentation is available. TPL-007-1 calls for PC/TPs to provide GIC time series data (R5), after which TO/GOs perform thermal assessments and suggest mitigating actions (R6). The PC/TPs then develop Corrective Action Plans (R7), which are not required to take into account the TO/GO-suggested actions and can include demands for, "installation, modification, retirement, or removal of transmission and generation facilities." The SDT representatives on the NAGF teleconference cited above stated that granting PC/TPs such sweeping powers over equipment owned by others is consistent with the precedent in TPL-001-4; but we disagree – TPL-001-4 is not even applicable to GOs and TOs. We have high regard for PC/TPs, and we agree that they should be involved in developing GMD solutions, but proposing to give them unilateral control over decisions potentially costing millions of dollars per unit is inequitable. This point is substantiated by the input from Dr. Marti of Hydro One (author of the reference #4 cited above) that they have never had to replace transformers for GMD mitigation; such actions as operational measures, comprehensive

monitoring, real time management and studies have been sufficient. R7of TPL-007-1 should be rewritten to require PC/TPs to reach agreement with GO/TOs regarding equipment modifications, replacements and the like.
Individual
David Thorne
Pepco Holdings Inc.
No
See Comments on items 2 and 4
No
: Screening models are not developed so this requirement puts the cart before the horse and the revised standard just proposes to move the due date out
Yes
Yes
The White papers are an attempt to explain the details but are not technically accurate. This is not a simple topic and much interpretation of the data is required. The response to GIC is related to the transformer ampere turns which determines the flux produced by the GIC. Increased flux increases the losses thus increasing temperatures. Without looking at the transformer design there is no way to be sure where the increase in flux or heating will create the hottest spot or where the heating will take place. Different transformers designs by different suppliers will react differently. A standard GIC profile curve with short duration peak and longer durations of GIC would allow a better delination of suspectable transformer designs rather than a hard number of 15 amperes per phase. Measurements of GIC and temperatures should be an allowable mitigation technique so the transformer response can be seen under many conditions and if needed the unit can be switched off line.
Group
Florida Municipal Power Agency
Carol Chinn
Yes
No
FMPA supports the comments of the FRCC GMD Task Force (copied below). The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an

implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of ‘priliminary’ with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force 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
FMPA does not agree with the SDT that failure to meet R4 or R7 could DIRECTLY cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures during a 1-in-100 year GMD event, and continues to believe the VRFs for these requirements should be lowered to medium.
Yes
FMPA supports the comments of the FRCC GMD Task Force (copied below). The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) 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 FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; “The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies.” The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess

implementation timeframes and establish the appropriate levels of funding and the requisite resources.
Individual
John Bee on Behalf of Exelon and its Affiliates
Exelon
Yes
Yes
Yes
Yes
The Exelon affiliates would like to express concern with the reliance on transformer manufacturers to conduct the transformer thermal assessment identified in requirement 6. Specifically, our concern is that some transformer manufacturers may not be willing or able to perform the transformer thermal assessments or to provide the required data to conduct transformer thermal assessments in house. We understand that generic transformer models will be made available in the near future and that software tools will also be available to industry, which will utilize these generic transformer models that can be used should the transformer manufacturer be unable or unwilling to perform the thermal assessments. We believe that this approach could produce overly conservative results which may cause the implementation of mitigation measures that would otherwise be unnecessary if the transformer manufacturer data were used so that more accurate results would be achieved. At least one manufacturer has expressed concern that the use of generic models is incorrect because it does not take into account specific design parameters that only the manufacturers have access to. We also understand the implementation plan for TPL-007 will allow time for industry and the transformer manufacturers to work out the methodology and process associated with conducted transformer thermal assessments. Exelon would urge the transformer manufacturers and the NERC GMD Task Force come to a consensus and provide the necessary support and engagement with industry as well as groups supported by industry in developing transformer models and conducting transformer thermal assessments. We would ask that the Standard Drafting Team review the comments submitted by the transformer manufacturers and address them as appropriate.
Individual
Richard Vine
California ISO
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
Individual
PHAN, Si Truc
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Hydro-Québec has the following concerns with the proposed standard: 1. The GMD Benchmark Event is too severe to be considered as normal event and should be used as a Extreme situation – the drafting team chose to maintain the 8v/Km value and considers that the 1/100 year should be equivalent to Category C and not Category D of current TPL standards. Hydro-Québec concurs with Manitoba Hydro's objection on this point. TPL-007 should follow a format with normal and extreme events, with different compliance requirements. A smaller scale GMD Benchmark Event should be considered as normal event. This is not a minority position, since both Manitoba and Québec's electric systems cover a non-negligible portion of Canada. 2. The GMD Benchmark Event is too preliminary to be applied on Hydro-Québec's system and enforce compliance : ♣ The study used statistical value of B and convert this into E. The conversion uses conservative hypothesis which provide approximation that do not reflect HQ's reality. The study consider, for an area of 200 km, a constant value of E which does not reflect a realistic situation for Hydro-Québec with a 1,000 km long system. The GMD Event should better take into consideration that the magnetic field and electric field are not constant (e.g. E=f(t)) nor uniform (e.g. E=f(x,y)) when studied on a large distance. It depends on time and location. ♣ The direct readings of E should be taken into consideration before retaining the GMD Benchmark Event. Some real measured E values exist and should be used to identify the GMC Event. ♣ The 5 to 8 V/Km is too high for the Hydro-Québec System. The highest global value observed is less than 3 V/Km. The frequency of the maximum local peak value have been observed for less than two minutes over a 167 month period. That could imply enormous investments on the system to comply to this theoretical GMD Event. 3. Even though the drafting team refers to different guides, it appears that the GMD Vulnerability Assessment is not clear enough. Concurring also with Manitoba comment no 4, the drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The harmonic analysis is missing in the standard. 4. At the 1989 event and after, Hydro-Quebec has not experienced any transformer damage due to GIC and have put strong efforts to test and

study GIC effect on Transformer. The 15 A criterion is too simplistic and does not take into account the real operating condition and type of transformer. The evaluation proposed in R6 causes a burden that is not relevant for utilities with high power transformers. 5. TPL-007-1 should be consistent with the philosophy applied in Standard PRC-006. In the latter standard, the TP must conduct an assessment when an islanding frequency deviation event occurs that did or should have initiated the UFLS operation. Similarly, if GMD actually causes an event on the system, then the TP or PC should simulate the event to ensure model adequacy (as per R2) and Assessment Review (as per R4) . 6. From a compliance perspective, there is no mention of what the Responsible entity as determined in R1 is supposed to do with the info provided by the TOs and GOs in R6.4. If the thermal impact assessments are supposed to be integrated in the GMD Vulnerability Assessment, it should be specified in R4. 7. The time sequence and delays are unclear regarding requirements R4, R5 and R6. Many interpretations are possible; the following is one example: a- GMD Vulnerability Assessment 1 (R4) b- GIC flow info (R5) c- Thermal impact assessment and report 24 months later d- Integration in GMD Vulnerability Assessment 2. Since assessments are performed about every 5 years, GMD Vulnerability Assessment 2 will only occur 3 years after reception of the thermal impact assessment? The DT should clarify the time sequence and delays between requirements R4, R5 and R6.
Individual
John Pearson/Matt Goldberg
ISO New England
Yes
No
We agree with extending the implementation plan to 60 months. However, more time for the development of the Corrective Action Plan under Requirement R7 should be provided within those 60 months. Once a Corrective Action Plan for one transformer is developed, the entity responsible for developing the Corrective Action Plan will have to run the model again to determine whether another Corrective Action Plan for other transformers is needed as a result of the first Corrective Action Plan. This step may have to be repeated several times. Thus, the time that the entities responsible for developing Corrective Action Plans have from the time they receive the results of the thermal impact assessments under Requirement R6 (which under the current timeline is only 12 months) is insufficient. Accordingly, we strongly suggest that the time for implementation of Requirement R6 be changed from 48 months to 42 months. The time for implementation for Requirement R7 would remain at 60 months but responsible entities would have 18 months to develop the Corrective Action Plans.
Yes
Yes

Section 4.2 in the Applicability section of the standard should be revised to state as follows: “Transformers with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” As the SDT explained in its answer to comments received on this section during the previous comment period, the standard applies only to transformers, so the words “[f]acilities that” at the beginning of the sentence are unnecessary and can lead to confusion. TPL-007 Requirement R2 should require rotation of the field to determine the worst field orientation. Without this explicit requirement, a Responsible Entity could miss important GMD impacts and, as a result, the standard may not achieve its stated purpose of “establish[ing] requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon.” If the Standard Drafting Team does not include this in Requirement R2, then at the least the Standard Drafting Team should include it in the Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System.
Group
Seattle City Light
Paul Haase
Yes
Yes
Seattle City Light is concerned with the effectiveness of the proposed approach (considerations of scientific and engineering understanding aside). Seattle is a medium-small vertically integrated utility, and like many such entities, is registered as a Planning Coordinator and Transmission Planner for our system and our system alone. And like many similar entities, we are closely connected with a large regional transmission utility (Bonneville Power Administration in our case). For this type of arrangement a GMD Vulnerability Assessment performed by Seattle (acting alone) on Seattle’s own system (considered alone) will be of little or no value. GMD assessments by other, similarly situated entities likewise will have little or no value. Recognizing the large number of such entities in WECC (something like half of the Planning Coordinators in all of NERC) and the Pacific Northwest, Seattle and others presently are coordinating with regional planning bodies in an effort to arrange some sort of common GMD Vulnerability Assessment that could promise results of real value across the local region. Aside from the usual difficulties attendant upon such an exercise in collaboration, the wording of Requirement R1 that assigns responsibility to Planning Coordinators individually introduces administrative compliance concerns that hinder coordination. Seattle asks that the Drafting Team consider alternative language for R1 (and Measure M1) that would more clearly allow, if not encourage, the possibility for local collaboration among Planning Coordinators. If such changes are not possible, a second best solution would be a paragraph in the guidance documentation stating that collaboration among Planning Coordinators is considered to be a means of meeting compliance with R1.

Individual
David Kiguel
David Kiguel
Yes
R4 provides for completion of Vulnerability Assessments once every 60 calendar months. As written, it could result in assessments performed as far appart as 120 months of each other if one is completed at the beginning of a 60-month period and the subsequent assessment is completed at the end of the following 60-month period. I suggest writing: once every 60 calendar months with no more than 90 months between the completion of two consecutive assessments. Considerable investment expenses could be necessary to comply with the proposed standard. As such, the standard should not proceed without a solid cost/benefit analysis to justify its adoption, especially considering the low frequency of occurrence of events (the frequency of occurrence of the proposed benchmark GMD event is estimated to be approximately 1 in 100 years). Given the low probability, moderate loss of non-consequential load could be acceptable.
Group
Duke Energy
Colby Bellville
Yes
No
Based upon our review of the Implementation Plan, it appears that the proposed timelines for some of the requirements (specifically R4 & R5) may not coincide properly. We request further explanation of the timelines, and their relationships between the various requirements.
Yes
No
Individual
Bill Fowler
City of Tallahassee
No
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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. 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 Standard Drafting Team (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.
Individual
Mahmood Safi
Omaha Public Power District
No
The Omaha Public Power District (OPPD) is concerned with language in "Table 1 - Steady State Planning Events" that requires entities to perform steady state planning assessments based on "Protection System operation or Misoperation due to harmonics during the GMD event". The Planning Application Guide's Sections 4.2 and 4.3 specifically mention the unavailability of tools and difficulty in performing an accurate harmonic assessment but does not provide resolution or recommendation on how to accurately address the concern. The statement from Section 4-3 is referenced below. "The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results." Additionally, there needs to be a clearer definition of how the steady state planning analysis due to GMD event harmonics is to be performed. Is it the intent of the standard to study the removal of all impacted Transmission Facilities and Reactive Power compensation devices simultaneously, sequentially, or individually as a result of Protection operation or Misoperation due to harmonics? The Planning Application Guide references the "NERC Transformer Modeling Guide" in several places as a reference for more information on how to perform the study.

The “NERC Transformer Modeling Guide” is shown in the citations as still forthcoming. OPPD doesn’t believe this standard should be approved prior to the industry seeing the aforementioned transformer modeling guide. Further, OPPD does not believe it is feasible to implement a full harmonic analysis in the implementation timeframe for TPL-007. In a very broad view, the standard requires a specific analysis that the industry doesn’t have the skill set or tools to perform. This is acknowledged by the supporting documents. The reference document cited as a resource to further explain how to perform the studies has not been created yet.
No
Please refer to comments in Question 1.
Yes
No
Individual
Mark Wilson
Independent Electricity System Operator
Yes
Yes
Yes
The IESO respectfully submits that the SDT has not provided guidance on achieving an acceptable level of confidence that mitigating actions are needed. To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed from service, we suggest that the SDT add a requirement that says “the TO and GO shall seek the PC’s and TP’s concurrence or approval of thermal analysis technique selection”. The IESO also concurs with Manitoba Hydro and Hydro –Quebec comment that the SDT has not provided guidance on what are acceptable assumptions to make when determining which facilities should be removed as a result of a GMD event. The IESO respectfully reiterates our suggestion to amend the planning process to achieve an acceptable level of confidence as follows: 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.
Group

Con Edison, Inc.
Kelly Dash
No
The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type 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 and appropriate. On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads: “Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network model.” Suggest adding the following paragraph afterwards: “Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model.” This comment was submitted during the last comment period.
Yes
FAC-003 avoids using the phrase “terminal voltage” by using the phrase “operated at 200kV or higher.” Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the

200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read "…wye-grounded winding with voltage terminals operated at 200kV or higher". On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x α x β (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of "antenna" effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections. This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.
Group
Associated Electric Cooperative, Inc.
Phil Hart
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
Group
IRC SRC
Greg Campoli
No
1. The ISO/RTO Standards Review Committee (SRC) respectfully submits that the modifications to the measure remove the ability of Planning Coordinators to vet and implement protocols that are broadly applicable to Transmission Planners in its footprint through a consensus process. The requirement to develop individual protocols in coordination with each and every Transmission Planner individually creates unnecessary and unduly burdensome administrative processes that lack a corresponding benefit. The requirement and measure should be modified to allow Planning Coordinators to utilize consensus processes generally and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, th SRC notes that the modeling data itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since that standard deals with load flow, stability, and short circuit data. Accordingly, the SRC recommends that requirements R2 and R3 from MOD-032 be added as requirements in the beginning of the GMD standard and substitute the word "GMD" where it states "steady-state, dynamic, and short circuit". These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. In addition to adding the requirements noted above, the below revisions are proposed: R1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall delineate the individual and joint responsibilities of the Planning Coordinator and these entities in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). [Violation Risk Factor: Low] [Time Horizon: Long-term Planning] M1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall

provide documentation on roles and responsibilities, such as meeting minutes, agreements, and copies of procedures or protocols in effect that identifies that an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1. Corresponding revisions to VSLs are also recommended. 2. The SRC notes that the use of the term “Responsible Entities” “as determined under Requirement R1” is ambiguous and could be modified to be more clearly stated. The below revisions are proposed: “Entities assigned the responsibility under Requirement R1” Corresponding revisions for associated measures and VSLs are also recommended. 3. The SRC respectfully reiterates its comment 2 above regarding the term “Responsible Entities” “as determined under Requirement R1” and recommends that, for all instances where “Responsible Entity” is utilized in Requirement R3, similar revisions are incorporated. Corresponding revisions for associated measures and VSLs are also recommended. 4. The SRC respectfully reiterates its comment 3 above for all instances where “Responsible Entity” is utilized in Requirement R4. It further notes that Requirement R4 is ambiguous as written. More specifically, the second sentence could more clearly state expectations. The following revisions are proposed: R4. Entities assigned the responsibility under Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, include documentation of study assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] Corresponding revisions for associated measures and VSLs are also recommended. 5. The SRC respectfully reiterates its comment 3 above for all instances where “Responsible Entity” is utilized in Requirement R5. Additionally, for Requirement R5, no timeframe is denoted for provision of the requested data. To ensure that requested or necessary data is provided timely such that it can be incorporated in the thermal assessment required pursuant to Requirement R6. It is recommended that the requirement be revised to include a statement that the data is provided by a mutually agreeable time. Corresponding revisions for associated measures and VSLs are also recommended. 6. The SRC respectfully submits that, as written, Requirement R6 appears to require an individual analysis and associated documentation for each power transformer and does not allow Transmission Owners and Generator Owners to gain efficiencies by producing a global assessment and set of documentation that includes all required equipment. It further does not allow these entities to collaborate and coordinate on the performance of jointly-owned equipment, creating unnecessary administrative burden and reducing the exchange of information that could better inform analyses. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal

impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5; 6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and 6.4. 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. Corresponding revisions for associated measures and VSLs are also recommended. 7. As a global comment, the confidentiality of the information exchanged pursuant to the standard should be evaluated and, if necessary, the phrase "subject to confidentiality agreements or requirements" inserted in Requirements R3 through R7. Corresponding revisions for associated measures and VSLs are also recommended.
No
Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised.
No
1. Requirement R1 is a purely administrative requirement and, while important to ensure that all requirements are fully satisfied, should not be assigned a "Severe" VSL. A Moderate VSL is proposed. 2. Requirement R3 is a purely administrative requirement and, while important to ensure that system performance criteria are documented and understood, should not be assigned a "Severe" VSL. A Moderate VSL is proposed. 3. The VSL assigned to Requirement R2 penalizes the responsible entity for not maintaining "System model", which is already a requirement in MOD-032-1, R1. Assuming "GIC System model" includes "DC Network models" the VSL language assigned to Requirement R2 should be modified as follows: "The responsible entity did not maintain GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s)."
Yes
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. Specifically, Table 1 provides: "Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event" However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess "Misoperation due to harmonics". The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked. The SRC respectfully notes that this standard is unlike other NERC standards. While the SRC understands that the scope and assignment of the drafting team was to develop

standards to implement mitigation of GMD events, the industry has little experience in the matter and, as a result, the proposed standard is a composition of requirements for having procedures and documentation of how an entity performs a GIC analysis for GMD, which essentially makes the overall standard administrative in nature. The SRC would submit to the SDT that this is not the best use of resources and, as these comments point out, are quite removed from direct impacts on reliability. At a minimum, none of the requirements within this standard deserve High VSL ratings. In fact, it is highly probable that, if these requirements were already in effect today, they would be clear candidates for retirement under FERC Paragraph 81. While SRC understands that these requirements are the most effective way to address GMD risk at this time, the compliance resources involved to meet these requirements need to be considered on an ongoing basis and future efforts must be made to evolve the standard into more performance and result-based requirements, which would facilitate the retirement of the procedural/administrative requirements that currently comprise this standard.
Individual
Scott Langston
City of Tallahassee
No
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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. 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 Standard Drafting Team (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.
Group

FRCC GMD Task Force
Peter A. Heidrich
No
The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of 'priliminary' with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force 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.
Yes
The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC GMD Task Force requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; "The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting

GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies.” The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources. It has become very apparent that the SDT and NERC staff are unwilling to analyze the cost for implementation of this Standard, therefore, the FRCC GMD Task Force continues to request 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 GMD Task Force 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, which can be provided upon request.
Individual
Jo-Anne Ross
Manitoba Hydro
No
Note “System steady state voltages shall…” was removed from Table 1, which removes the link back to requirement R3. Note d should be re-established and the language similar to that used in TPL-001-4 should be considered: “System steady state and post-Contingency voltage performance shall be within the criteria established by the Planning Coordinator and the Transmission Planner.”
Yes
Yes
Yes
Manitoba Hydro has five main concerns with the proposed standard: 1. GMD Benchmark Event is too severe - We have made comments previously that we disagree with making a 1/100 year event equivalent to a “Category C” event (as defined in the current TPL standards) in terms of performance requirements. Comments have been made by the drafting team that this is a minority position. Manitoba Hydro’s objections are: a) A 1/100 year event “Category D” event is not mandated in Order 779. The FERC Order 779 states “… of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity

must assess for potential impacts on the Bulk-Power System." b) Manitoba Hydro does not want this to be precedent setting for opening up a review of the extreme events in the current TPL standards and raising the bar for these disturbances in the future. The Transmission Owner should be in the best position to judge their level of risk exposure to extreme events in terms of benefits vs. costs. 2. Thermal Assessments not necessary - We have made recommendations to remove the transformer thermal assessments from TPL-007; specifically remove requirements, R5 and R6. The reason is based on: a) these requirements being burdonesome on utilities in northern latitudes, Transformer thermal assessments should be limited to transformers that have a confirmed wide area impact to minimize the assessment burden. b) these requirements are based on science that is still evolving, The drafting team is still in the process of finalizing the thermal impact assessment whitepaper. This supporting document should be finalized prior to recommending mandatory standards. c) these requirements having limited reliability benefits, Currently, requirement R6.3 only requires the development of suggested actions. There is no requirement to implement the suggested actions. If no actions are mandated then why is the analysis required? Rather than using a 15 A per phase metric, perhaps R4.4 and R4.5 from TPL-001-4 could be used for guidance where the Planning Coordinator identifies the transformers that are lost or damaged are expected to produce more severe System impacts (eg Cascading) as well as an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence. Such an approach would limit the number of transformers requiring assessment to a manageable number. d) these requirements are not mandated in Order 779. Order 779 does not clearly mention that transformer thermal assessments are required. However, one of the FERC Order 779 requirements implies that a thermal assessment should be done: "If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event." Damage to critical or vulnerable BPS equipment implies damage due to thermal stress. FERC 779 requires testing for instability, uncontrolled separation or cascading as a result of damage to a transformer or transformers. The TPL-007 standard as drafted does not require an assessment of the impacts of potential loss of a several transformers due to excessive hot spot temperature. Presumably, the hot spot temperature would not coincide to the 8 V/km peak of the benchmark GMD event. The drafting team should specify at what level of GMD (eg 1 V/km) it might be expected that transformers would trip due to hot spot temperature. 3. The TPL-007 standard does not address all of FERC Order 779 - as drafted TPL-007 does not include an assessment of the impacts of equipment lost due to damange that result in instability, uncontrolled separation or cascading failures on the BPS. FERC Order 779 states, "If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event." Instead it appears that the TPL-007 approach may

(R6.3 is not worded clearly as to whether or not mitigation is required) require that all elements impacted by thermal heating get mitigated independ of whether or not their loss results in instability, uncontrolled separation or cascading failures on the BPS. Requiring mitigation on elements for which their loss does not result in instability, uncontrolled separation or cascading failures may result in unnecessary costs with no reliability benefits. 4. Harmonic Analysis is missing -The drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The approach proposed in the current standard probably wouldn't have prevented the 1989 Hydro Quebec event. The 1989 event was a lesser event (compared to the 1-in-100 year benchmark event) in which system MVAR losses as a result of GIC were relatively insignificant and transformer thermal heat impacts were negligible. The 1989 black out occurred due to protection mis-operations tripping of SVCs due to harmonics, which then triggered the voltage collapse. Unfortunately harmonic analysis tools, other than full electromagnetic transient simulation of the entire network, have not been developed to date. A suggestion is to at minimum require an assessment to identify a list of equipment which when lost due to GIC would result in instability, uncontrolled separation or cascading failures on the BPS. For example this would require the tripping of all reactive power devices (shunt capacitors) connected to a common bus. Equipment (such as SVCs and shunt capacitors) that have been checked to ensure protection neutral unbalance protection is unlikely to misoperate or that are immune to tripping due to harmonic distortion would be exempt (equipment may still trip due to phase current overload during periods of extreme harmonics. However, this is expected to be a local single bus or local area phenomena as opposed to region wide issue like in the Quebec 1989 event). 5. GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC's of 24.5 Amps and 20.2 Amps. Analysis of the EPRI SUNBURST GIC data also indicates that the ALL peak GIC values between 10 Amps to 24 Amps were measured in NERC's supposed geoelectric field cut-off zone (between 40 to 60 degrees geomagnetic latitude).
Individual
Karen Webb
City of Tallahassee
No
Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: 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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: 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 Standard Drafting Team (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.
Group
JEA
Tom McElhinney
JEA supports the comments of the FRCC GMD Task Force.
Group
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana
Erica Esche
Yes
Vectren proposes the SDT to consider a different approach to the Applicability and/or registered functions identified in R1. Consider modifying the Applicability section of TPL-007-1 to mirror CIP-014's Applicability section; 'Transmission Facilities that are operating … 200 kV and … above at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an 'aggregated weighted value' exceeding ### according the to the table (table to be created by SDT or to use the same from CIP-014). To identify the greatest

threat to the Bulk Electric System (BES), the SDT could revise Requirement R1's responsible registered functions to only the Planning Coordinator. Vectren believes the PC performing a system-wide assessment would be of greater value to the BES over including entities with less of an overall reliability impact to the BES. Data to perform the assessment is provided to the Planning Coordinator as part of existing MOD, FAC, and PRC standards.
Individual
Bill Temple
Northeast Utilities
Yes
Yes
Yes
Yes
It appears that the way Requirement 7.3 of the proposed standard is written presents the potential for competition conflicts under FERC Order 1000. Can the SDT provide feedback to the industry as to what, if any, impact evaluation was done on this requirement as it may impact FERC Order 1000.
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We would like to thank the SDT for already addressing many of our concerns regarding the previous drafts of this standard. However, we still have a concern regarding how the applicable entities are identified in this standard and recommend the SDT designate the Planning Coordinator as the applicable entity for compliance with Requirement R1. R1 lists both the PC and the TP as concurrently responsible for compliance, 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, should be the entity responsible for performing the GMD Vulnerability Assessment. The SDT identifies their justification for this approach is the same as the one taken in other planning standards, and while we appreciate an effort to maintain consistency between standards, this approach has forced many entities to plan and implement formal coordination agreements between PCs and TPs on a regional basis to identify the responsibilities of conducting these assessments. The approach spreads the burden of compliance among many entities rather than directly assigning the responsibilities to just a smaller set, the Planning Coordinators. We believe the SDT should remove each reference to "Responsible entities as determined in Requirement R1" and instead properly assign the PC. (2) We appreciate the SDT providing their justifications for a facility criterion with the applicability of this standard;

however, we believe the SDT should remove this criterion and instead utilize the current BES definition that went into effect on July 1, 2014. Like the SDT, we also acknowledge that parts of the proposed standard apply to non-BES facilities and that some models need such information to accurately calculate geomagnetically-induced currents. However, that criterion should be identified within the Guidelines and Technical Basis portion of the standard. Adding the facility criterion upfront in the applicability section of the standard provides confusion to both industry and auditors when 200 kV high-side transformers may apply. The BES definition identifies all Transmission Elements operated at 100 kV or higher and accounts for inclusions and exclusions to that general definition. The SDT should leverage the technical analysis that was performed to achieve industry consensus and FERC approval for the revised BES definition. The current approach only provides additional confusion.
No
We appreciate the SDT's recognition that the previous implementation plan identified for this standard was too short and burdensome for entities. More time and information need to be made available for entities to properly construct the necessary data models and conduct these new studies correctly. Entities have also received limited assistance with their vendors on the provision of the data necessary to conduct these studies. Large and small entities have limited resources, software, and industry knowledge in this area. Moreover, for smaller entities with limited staff and financial resources, this effort will be a significant challenge. We continue to recommend that the implementation period be extended to eight years to allow industry an opportunity to fully engage in this effort.
No
We appreciate the SDT's efforts to identify measureable criteria for many of the VSLs identified in this standard. However, we continue to disagree with the SDT's assignment of VRFs for this standard. The SDT identifies that they have aligned the VRFs with the criteria established by NERC. However, we want to remind the SDT of the planning horizon identified in this standard and not to confuse the nature of the event with insufficient or unsupported GMD Vulnerability and thermal impact assessments. We disagree with the categorization of Medium VRFs for the applicable requirements because these requirements could not "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System." While the nature of the event could affect the electrical state or capability of the BES, we believe not maintaining system models or identifying performance criteria for acceptable system steady state voltage limits would have no affect on the electrical state or capability of the BES.
No
(1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. Thank you for the opportunity to comment.
Individual
Sonya Green-Sumpter

South Carolina Electric & Gas
No
On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such having the same geomagnetic scaling factor for a footprint that covers a wide variety of latitudes and bedrock conditions. The individual the applicable entities should be allowed to use judgment in applying the scaling factors.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. This document has not yet been distributed and, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes, it would be useful to have the opportunity to review it.
Individual
Anthony Jablonski
ReliabiltiyFirst
Yes
ReliabilityFirst votes in the Affirmative and believes the TPL-007-1 standard enhances reliability and establishes requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events. ReliabilityFirst offers the following comments for consideration 1. Requirement R7 - During the last comment period ReliabilityFirst provided a comment on Requirement R7 which suggested that R7 should require the Entity to not only develop a Corrective Action Plan but "Implement" it as well. The SDT responded with "CAP must include a timetable for implementation as defined in the NERC Glossary". Even though the NERC definition of CAP implies that an entity needs to implement the CAP, ReliabilityFirst does not believe it goes far enough from a compliance perspective. ReliabilityFirst also notes that other NERC/FERC approved standards (PRC-004-2.1a R1 - "…shall develop and implement a Corrective Action Plan to avoid future Misoperations…" and PRC-004-3 – R6 "Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5…") require entities to "Implement the CAP" so ReliabilityFirst believes it is appropriate to in include this language. ReliabilityFirst offers the following language for consideration: "Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability

Assessment conducted in Requirement R4 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall:”
Individual
Brett Holland
Kansas City Power and Light
No
5. Background – Replace ‘Misoperation’ with ‘Misoperation(s)’. R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 – set the phrase ‘as determined in Requirement R1’ off with commas. R4 – Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load. Rationale Box for Requirement R4 – Capitalize ‘On-Peak’ and ‘Off-Peak’. Measure M5 – Insert ‘in the Planning Area’ between ‘Owner’ and ‘that’ in the next to last line of M5. Rationale Box for Requirement R5 – Capitalize ‘Part 5.1’ and ‘Part 5.2’. Likewise, capitalize ‘Part 5.1’ under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section. R6/M6 – Capitalize ‘Part 5.1’. Attachment 1 – We thank the drafting for providing more clarity in the determination of the β scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Yes
Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requiements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
No
Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs. R5 – Capitalize ‘Parts 5.1 and 5.2’ in the High and Severe VSLs for Requirement R5. R6 – Capitalize ‘Part 5.1’ and ‘Parts 6.1 through 6.4’ in the VSLs for Requirement R6. R7 – Capitalize ‘Parts 7.1 through 7.3’ in the Moderate, High and Severe VSL for Requirment R7.
Yes

We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics – Capitalize ‘Reactive Power’ in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics – Replace ‘Wide Area’ in the 1st line of the 6th bullet under General Characteristics. The lower case ‘wide-area’ was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term ‘Wide Area’ refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don’t believe the usage here is restricted to an RC’s Wide Area view. The lower case’wide-area’ is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude – In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the ‘GIC system model’. In Requirement R2 of the standard a similar reference is made to the ‘GIC System model’ as well as ‘System models’. In the later ‘System’ was capitalized. Should it be capitalized in this reference also? Statistical Considerations – In the 6th line of the 2nd paragraph under Statistical Considerations, insert ‘the’ between ‘for’ and ‘Carrington’. Statistical Considerations – In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase ‘1 in 100 year’ is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as ‘1-in-100’. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification – In the 3rd line of the 1st paragraph under the Justification section, the phrase ’15 Amperes per phase neutral current’ appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as ’15 Amperes per phase’. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification – In the 2nd paragraph under the Justification section, the term ‘hot spot’ appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn’t. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification – In the 4th line of the Figure 4 paragraph, ’10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.

Yes
Although Tri-State appreciates the intent of the language change in R3, we believe it's now ambiguous as to what is meant by "performance." What did the SDT have in mind with that change? How does the SDT imagine this to be audited? Tri-State believes there is an error in Attachment 1 of the standard. On page 11 under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use the largest Beta factor of physiographic regions or a technically justified value." However on page 22 of the GMD Benchmark White Paper under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use a Beta Factor of 1 or other technically justified value." These should be consistent and the Attachment in the standard should read as it does in the Benchmark White Paper. There is language already stating that the largest Beta Factor of 1 should be used in cases where entities have large planning areas that span more than one physiographic region.
Yes
Yes
Yes
On page 11 of the "Transformer Thermal Impact Assessment" White Paper it states "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." We are interested to know what is meant by "measured"? Does this have to be done in the lab or can this be done through monitoring of existing transformers?
Group
Iberdrola USA
John allen
Yes
Yes
Yes
Yes
Direction on the scope of reactive devices to be removed in the standard’s Table 1 should be provided. This would include number of devices and/or % within a geographic proximity. It is not clear whether all devices or only specified devices should be removed from service.
Individual
Catherine Wesley
PJM Interconnection
Yes

Yes
Yes
No
Individual
Gul Khan
Oncor Electric
Yes
Yes
Yes
No
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
We'd like to express our gratitude and acknowledge the SDT efforts in preparing this standard. We wish to encourage the standard drafting team to consider the flexibility for entities to meet the Requirement R1 through including regional planning groups or something equivalent in Requirement R1. This would allow an entity's participation in such planning groups to meet the terms of the requirement while providing a consistent study approach within a regional boundary. We believe this change meets FERC's intent while alleviating entities duplication of studies while providing a consistent approach on the regional basis. R1. Each Planning Coordinator "or regional planning group", in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). Thank you. Joe Tarantino, PE
Group
Bonneville Power Administration
Andrea Jessup

Yes
Yes
Yes
Yes
BPA notes that presently commercial study software does not have the functionality to evaluate the impact of GIC on a transformer; it needs to be capable of this in order to appropriately apply the screening criteria for the complexity of analyzing flows through a transmission network via a benchmark storm. The most significant need is for autotransformers as the core is exposed to an “effective current” influence for the actual flux saturation level which is from an additive or subtractive coupling of current flow in the common and series winding. BPA reiterates our question from the previous comment period: 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.
Group
Foundation for Resilient Societies
William R. Harris
No
COMMENTS OF THE FOUNDATION FOR RESILIENT SOCIETIES (Comment 1 of 2 submitted 10-10-2014) TO THE STANDARD DRAFTING TEAM NERC PROJECT 2013-03 – STANDARD TPL-007-1 TRANSMISSI0N SYSTEM PLANNED PERFORMANCE FOR GEOMAGNETIC DISTURBANCE EVENTS October 10, 2014 Answer to Question 1: No, we do not agree with these specific revisions to TPL-007-1. Detailed responses are below. Requirement R3 should contain steady state voltage “limits” instead of the subjective term “performance.” Measure M3 should contain steady state voltage “limits” instead of the subjective term “performance.” Table 1, “Steady State Planning Events” has been changed to allow “Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service” as primary means to achieve BES performance requirements during studied GMD conditions. When cost-effective hardware blocking devices can be installed, load loss should not be allowed. Protective devices that keep geomagnetic induced currents (GICs) from entering the bulk transmission system extend service life of other critical equipment, allow equipment to “operate through” solar storms, reduce reactive power costs and support higher capacity utilization. In contrast, load shedding while GSU transformers remain in operation tend to reduce equipment life and continue to allow GICs into the bulk power system, risking grid instabilities. Capacitive GIC blocking devices are, to first order, insensitive to uncertainties in GMD currents and thus protect the grid against a large range of severe GMD environments. Table 1, “Steady State Planning Events” has been changed to allow Interruption of Firm Transmission Service and Load Loss due to “misoperation due to

harmonics." When cost-effective hardware blocking devices can be installed, misoperation due to harmonics should be prevented. On page 12, text has been changed to "For large planning areas that span more than one β scaling factor from Table 3, the most conservative (largest) value for β should may be used in determining the peak geoelectric field to obtain conservative results." "May" is not a requirement; the verb "should" needs to be retained in the standard. Under "Application Guidelines," Requirement R6 now reads: "Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2 is also a justifiable threshold criterion that exempts a transformer from Requirement R6." These exemptions from the assessment requirements of this standard, both singly and in combination, defeat a key purpose of FERC Order No. 779, which is to protect the bulk power system from severe geomagnetic disturbances: (1) By failing to require the utilization of now-deployed and future-deployed GIC monitors, of which there were at least 102 in the U.S. in August 2014 (see Resilient Societies' Additional Facts filing, Aug 18, 2014, FERC Docket RM14-01-000), and now at least 104 GIC monitors, NERC fails to mandate use and data sharing from actual GIC readings, and cross-monitor corroboration of regional GIC levels. This systematic failure to use available risk and safety-related data may enable "low-ball modeling" of projected GIC levels both at sites with GIC monitors and at other regional critical facilities within GIC monitoring; (2) The so-called "benchmark model" developed by NERC significantly under-projects GICs and electric fields. The Standard Drafting Team, in violation of ANSI standards and NERC's own standards process manual, has failed to address on their merits, or refute with scientific data and analysis, the empirically-backed assertions of John Kappenman and William Radasky in their White Paper submitted to the Standard Drafting Team of NERC on July 30, 2014. See also the Resilient Societies' "Additional Facts" filing in FERC Docket RM14-01-000, dated Aug. 18, 2014. Using a smaller region of Finland and the Baltics as a modeling foundation, the NERC Benchmark model under-estimates geoelectric fields by factors of 1.5. To 1.9. This systematic under-estimation of geoelectric fields will have the effect of excluding entities that should be subject to the assessment requirements, thereby reducing the analytic foundation for purchase of cost-effective hardware protective equipment thus allowing sizable portions of the grid to be directly debilitated, with cascading effects on other portions of the grid. (3) In the NERC Standard Drafting Team's review of the Kappenman-Radasky White Paper submitted on July 30, 2014, the STD Notes claim: "They [the Standard Drafting Team] did not agree with the calculated e-fields presented in the commenter's white paper for the USGS ground model and found that the commentator's result understated peaks by a factor of 1.5 to 1.9" Meeting Notes, Standard Drafting Team meeting, August 19 [20014] Comment Review, page 2, para 2b, at page 3. This is altogether garbled. The commenters, using empirical data from solar storms in the U.S. and not in Finland, found the benchmark model understated GICs and volts per kilometer by a factor of 1.5 to 1.9. The Standard Drafting Team has submitted the standard to a subsequent ballot without addressing the Kappenman-Radasky White Paper critique on its merits. This is a violation of both ANSI standards and the NERC standards process manual requirements. (4) To exempt mandatory assessments if a transformer manufacturer's design specifications claim transformer withstand tolerances above the benchmark-projected amps per phase is to place grid reliability upon a foundation of quicksand. (A) Manufacturers generally do not test high voltage transformers to destruction, so their certifications of equipment tolerances are scientifically suspect; (B) As the JASON Summer study report of 2011, declassified in December 2011, indicates: a review of the warranties included with most high voltage transformer sales contracts exclude liability for transformer failures due to solar weather, so "transformer ratings" are not guaranteed and are not backed by financial reimbursement for equipment losses or resulting loss of business claims. The JASONs concluded it was more prudent to purchase neutral ground blocking devices than to pay to test extra high voltage transformers and still risk equipment loss in severe solar weather; (C) The claims of transformer manufacturers have been disputed by national experts, so without testing by a neutral third party, such as a DOE national energy laboratory, these claims are suspect, and should not, without validated third party testing, be an allowable exclusion from mandatory assessment by all responsible entities. See, for example, the Storm Analysis Consultants Report Storm R-112, addressing various unsubstantiated claims by ABB for various transformers. Storm-R-112 noted a number of ABB claims that could not be substantiated. Moreover, in transformer ratings provided to American Electric Power, Kappenman asserts that manufacturer reports have failed to address the most vulnerable winding on the transformer, the tertiary winding. John Kappenman informed the Standard Drafting Team that measurable GIC withstand was much lower than what the manufacturer had estimated for one tested transformer. He further explains that tests carried out by manufacturers only have been able to go up to about 30 amps per phase and were set up to actually exclude or inhibit looking at the most vulnerable tertiary winding on tested transformers. Papers submitted to IEEE and CIGRE discuss these tests but ignore the tertiary winding vulnerabilities. Hence these nonrigorous, manufacturer-biased "ratings" should not, without third party validation, exempt an entity from assessment responsibilities under this standard. (5) The submission of comments today, October 10, 2014, by John Kappenman and Curtis Birnbach, further invalidates the NERC Benchmark model as a basis to design vulnerability assessments. Both the alpha factor and the beta factor of the NERC model significantly under-project GICs and geoelectric field of anticipated quasi-DC currents. The so-called "benchmark" standard is not ready for prime time. If the Standard Drafting Team fails to address the systematic biases in its modeling effort, if it fails to utilize U.S. data and not Finland and Baltic region data, if it fails to require modeling based on the full set of 104 GIC monitors and future added GIC monitors, NERC will be in violation of its ANSI obligations and in violation of the standard validation process set forth in NERC's own Standards Process Manual adopted in June 2013. (6) Resilient Societies reported to the GMD Task Force as far back as January 2012 that vibrational impacts of GICs were the proximate cause of a 12.2 day outage of the Phase A 345 kV three-phase transformer at Seabrook Station, New Hampshire on November 8-10, 1998. Magnetostriction and other vibrations of critical

equipment are associated with moderate solar storms. A moderate North-South/South-North reversing solar storm caused ejection of a 4 inch stainless steel bolt into the winding of the Phase A transformer at Seabrook, captured by FLIR imaging as the transformer melted on November 10, 1998. NERC’s own compilations on the March 1989 Hydro-Quebec storm records contain dozens of separate reports of vibration, humming, clanging, and other audible transformer noise at locations within the U.S. electric grid at the time that the GSU transformer at Salem Unit 1 melted. More recently, tests at Idaho National Laboratory in 2012, reported by INL and SARA in scientific papers in 2013, confirm that GICs injected into 138 kV transmission lines cause adverse vibrational effects; and that neutral blocking devices eliminate these vibrational effects. It is arbitrary and capricious for the NERC Standard Drafting Team to fail to address vibrational effects of GMD events, and vibrational elimination when neutral ground blocking equipment is installed. Even if the Standard Drafting Team would prefer a standard that discourages any obligation to install neutral ground blocking devices, such an outcome does not comply with ANSI standards. Evidence-based standards are needed. Excluding an entire category of risks (magnetostriction and other vibrations) that are well documented in literature on vibrational risks in electric grids should be unacceptable to NERC, to FERC, and to ANSI. (7) The Standards Drafting Team did not act to address our comments submitted on July 30, 2014, in violation of ANSI requirements that comments be addressed. Areas not addressed include, but are not limited to: (A) No adjustment for e-field scaling factors at the edge of water bodies. (B) No standard requirement for the assessment of mechanical vibration impacts. (C) No requirement for testing of transformers to validate thermal and mechanical vibration withstand when subjected to DC current limits. (8) Our concerns with NERC’s speculative “hot spot” conjecture for GIC impacts over wide areas were not addressed. Under separate cover to NERC, we are submitting data and analysis that shows NERC’s “hot spot” conjecture is inconsistent with real-world data. In conclusion, we note that the Federal Energy Regulatory Commission in its Order No. 779 [143 FERC ¶ 61,147, May 16, 2013) ordered “that any benchmark events proposed by NERC have a strong technical basis.” Emphasis added, quoting Order No. 779 at page 54. For the above reasons, among others, NERC’s draft standard TPL-007-1 does not presently have a “technical basis” for its implementation, let alone a “strong technical basis” as required by FERC’s Order.
Yes
With a 60 month implementaiton period, it would be highly beneficial to utilize and require data sharing for the 104 or more GIC monitors now operational in the United States. See Foundation's "Additional Facts" filing in FERC Docket RM14-1-000 of Aug 18, 2014. A model using all the GIC monitors operating now or in the future would enable more cost-effective operating procedures and hardware protection decisions.
Yes
Yes
The Foundation for Resilient Societies submits these Comment 1 of 2, and separately. A second comment submitted on Oct 10 2014 involves graphics for concurrent GIC spikes at

near-simultaneous times hundreds or even thousands of miles apart. These findings refute the unsubstantiated "GIC Hotspot" model used to average down the effective GIC levels. This bias, combines with the alpha modeling bias (See Kappenman-Radasky White Paper submitted on July 30, 2014) and the beta modeling bias (See Kappenman-Birnbach comments 10-10-2014) in combination result in the NERC GMD Benchmark Model under-estimating overall geoelectric fields and risks to critical equipment by as high as one order of magnitude. Unless corrected, cost-effective purchases of protective equipment will be needlessly discouraged, and the grid will remain at needless risk. ANSI standards and NERC's standards process manual require addressing flaws and criticisms on their merit. This has not been done!
Group
PacifiCorp
Sandra Shaffer
No
Please refer to the response for #4.
Yes
Yes
PacifiCorp is voting no on this ballot to reflect our concerns (a) that insufficient evidence has been presented to show that the potential impact of a geomagnetic disturbance is significant for the majority of the North American electrical grid, and (b) that the effort that will be required to fully comply with this standard as drafted is not commensurate with the risk. However, PacifiCorp would support this effort if the initial implementation was limited to areas with the highest levels of perceived risk such as areas, for example, above 50 degrees of geomagnetic latitude and within 1000 kilometers of the Atlantic or Pacific coasts. Based on this approach, methods and tools used for the assessment can be further developed while addressing those areas most at risk. PacifiCorp’s concerns can be summarized as follows: (1) The SDT had not provided adequate evidence to show that the impacts of Geomagnetic disturbance are significant at lower latitudes. (2) The at-risk areas for impacts on the transmission system due to Geomagnetic disturbance are limited. The SDT should consider applying this standard only to utilities above 60° geomagnetic latitude until adequate data and evidence is available to show lower latitude utilities are impacted to the same degree as higher latitude utilities. (3) In cases where an assessment is deemed necessary, the SDT should consider adding a specific provision where the utilities will be allowed to use prior cycle study results unless a stronger solar storm has been detected than the test signal or significant changes have occurred in the transmission system. Such a provision will reduce the burden on utilities and their customers.
Individual
Wayne Guttormson
SaskPower

Yes
1. GMD Benchmark Event appears to be an extreme event - Making a 1/100 year event equivalent to a “Category C” event in terms of BES performance does not seem supported. 2. Thermal Assessments do not seem to be supported. In general, transformer thermal assessments should be limited to transformers that have a confirmed wide area impact. a) the science is still evolving, b) reliability benefits seem limited,& c) not mandated in Order 779.

Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1
Submitted to NERC on October 10, 2014

Executive Summary

The NERC Standard Drafting Team has proposed a Benchmark GMD Event based on a 1-in-100 year scenario that does not stand up to scrutiny, as data from just three storms in the last 40 years greatly exceed the peak thresholds proposed in this 100 Year NERC Draft Standard. The Standard Drafting Team then developed a model to estimate Peak Electric Fields (Peak E-Field) at locations within the continental United States for use by electric utilities that also has not been validated and appears to be in error. In these comments technical deficiencies are exposed in both the Benchmark GMD Event and the NERC E-Field model. These deficiencies include:

1. The NERC Benchmark GMD Event was developed using a data set from geomagnetic storm observations in Finland, not the United States.

2. The NERC Benchmark GMD Event was developed using a data set from a time period which excluded the three largest storms in the modern era of digital observations and does not include historically large storms.

3. The NERC Benchmark GMD Event excludes consideration of data recorded during geomagnetic storms in the United States in 1989, 1982, and 1972 that show the NERC benchmark is significantly lower than real-world observations.

4. While it is well-recognized that Peak dB/dt from geomagnetic storms vary according to latitude, observed real-world data from the United States shows that the NERC latitude scaling factors are too low at all latitudes. For storms observed over a 100 year period, NERC latitude scaling factors would be significantly more in error.

5. While it is well-recognized that Peak Electric Fields from geomagnetic storms vary according to regional ground conditions, observed real-world data from the United States shows that the NERC geo-electric field simulation models are producing results that are too low and may have embedded numerical inaccuracies.

6. When the estimated E-Field from the NERC model is compared to E-Field derived from measured data at Tillamook, Oregon during the Oct 30, 2003 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 5.

7. When the estimated E-Field from the NERC model is compared to the E-Field derived from measured data at Chester, Maine during the May 4, 1998 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 2.

8. The errors noted in points 5 and 6 become compounded when combined to determine the NERC Epeak levels for any location. The erroneous NERC latitude scaling factor, and the erroneous NERC geo-electric field model are multiplied together which compounds the errors in each part and produces an enormous escalation in overall error. In the case of Tillamook, it produces results too low by a factor of 30 when compared with measured data.

9. The NERC Benchmark GMD Event, NERC latitude scaling factors, and the NERC geo-electric field model do not use available data from over 100 Geomagnetically-Induced Current monitoring locations within the United States.

In conclusion, the NERC Standard has been defectively drafted because the Standard Drafting Team has chosen to use data from outside the United States and which excludes important storm events to develop its models instead of better and more complete data from within the United States or over more important storm events. GIC data in particular is in the possession of electric utilities and EPRI but not disclosed or utilized by NERC for standard-setting and independent scientific study. The resulting NERC models are systemically biased toward a geomagnetic storm threat that is far lower than has been actually observed and could have the effect of exempting United States electric utilities taking appropriate and prudent mitigation actions against geomagnetic storm threats.

The circumstances presented by this NERC standard development process are extraordinarily unusual, to say the least. Any other credible standards development organization that has ever existed would want to take into consideration all available data and observations and perform a rigorous as possible examination to guide their findings, fully test and validate simulation models etc. Yet this NERC Standards Development Team has decided to not even bother to gather and look at enormously important and abundant GIC data and develop useful interpretations and guidance that this data would provide. NERC has also refused to gather known data on other transformer failures or recent power system incidents that might be associated with geomagnetic storm activity. NERC has developed findings and standards that are entirely based upon untested and un-validated models, models which have also been called into question. These models further put forward results that in various ways actually contradict and ignore the laws of physics. The NERC Standard Development Team behavior parallels to an agency responsible for public safety like the NTSB refusing to look at airplane black box recorder data or to visit and inspect the crash evidence before making their recommendations for public safety. Such behaviors would not merit public trust in their findings.

Discussion of Inadequate Reference Field Storm Peak Intensity and Geomagnetic Field Scaling Factors

As Daniel Baker and John Kappenman had noted in their previously submitted comments in May 2014, there have been a number of observations of geomagnetic storm peaks higher than those in the NERC proposed in TPL-007-1 Reference Field Geomagnetic Disturbance[1]. The purpose of this filing is to further elaborate upon the NERC Draft Standard inadequacies and to also propose a new framework for the GMD Standard.

It is the role of Design Standards above all other factors to protect society from the consequences possible from severe geomagnetic storm events, this includes not only widespread blackout, but also widespread permanent damage to key assets such as transformers and generators which will be needed to provide for rapid post-storm recovery. It is clear that the North American power grid has experienced an unchecked increase in vulnerability to geomagnetic storms over many decades from growth of this infrastructure and inattention to the nature of this threat. In order for the standard to counter these potential threats, the standard must accurately define the extremes of storm intensity and geographic

[1] Daniel Baker & John Kappenman “Comments on NERC Draft GMD Standard TPL-007-1 – Problems with NERC Reference Disturbance and Comparison with More Severe Recent Storm Event”, filed with NERC for Draft Standard TPL-007-1, May 2014

footprint of these disturbances. It is only then that the Standard would provide any measure of public assurance of grid security and resilience to these threats.

It is clear from the prior comments provided by a number of commenters that the NERC TPL-007-1 Draft Standard was not adequate to define a 1 in 100 year storm scenario and was not conservative as the NERC Standards Drafting Team claims. Further the NERC Standards Drafting team has not proceeded in their deliberations and developments of new draft standards per ANSI requirements. In developing the Draft 3 Standard now to be voted on and prior drafts, the Standard Drafting Team did not address multiple comments laying out technical deficiencies in the NERC storm scenario. According to the ANSI standard-setting process, comments regarding technical deficiencies in the standard must be specifically addressed.

Figure 1 provides a graphic illustration of the NERC Standard proposed geomagnetic field intensity in nT/min, adapted from Table II-1 of α "Alpha" scaling of the geomagnetic field versus latitude across North America[2].

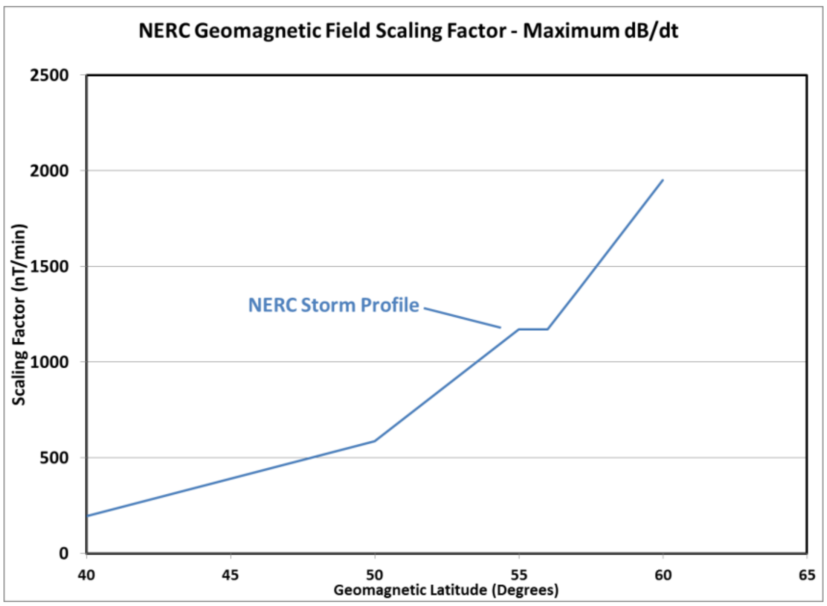

Figure 1 - NERC Proposed Profile of Geomagnetic Disturbance Intensity versus Geomagnetic Latitude

NERC has developed the intensity and profile described in Figure 1 from statistical studies carried out using recent data from the Image Magnetic observatories located in Finland and other Baltic locations[3]. This data base is a very small subset of observations of geomagnetic storm events, it is limited in time and does not include the largest storms of the modern digital data era and is limited in geography as it only focuses on a very small geographic territory at very high latitudes. The lowest latitude observatory in the Image array is at a geomagnetic latitude approximately equivalent to the US-Canada border, so this data set would not be able to explore the profile at geomagnetic latitudes below 55° and therefore reliably characterize the profile across the bulk of the US power grid. The NERC Reference Field excludes the possibility of a Peak disturbance intensity of greater than 1950 nT/min and further excludes that the peak could occur at geomagnetic latitudes lower than 60°. As observation data and other scientific analysis will show, both of these NERC exclusions are in error.

[2] Page 20 of NERC Benchmark Geomagnetic Disturbance Event Description, April 21, 2014.

[3] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

For the NERC Reference profile of Figure 1 to be considered a conservative or 1 in 100 year reference profile, then no recent observational data from storms should ever exceed the profile line boundaries. However as previously noted, the statistical data used by NERC excluded world observations from the large and important March 1989 storm and also from two other important storms that took place in July 1982 and August 1972, a time period that only covers the last ~40 years. In addition, data developed from analysis of older and larger storms such as the May 1921 storm have been excluded by NERC in the development of this reference profile. In just examining the additional three storms of August 4, 1972, July 13-14, 1982, and March 13-14, 1989, a number of observations of intense dB/dt can be cited which exceed the NERC profile thresholds. Figure 2 provides a summary of these observed dB/dt intensities and geomagnetic latitude locations that exceed the NERC reference profile.

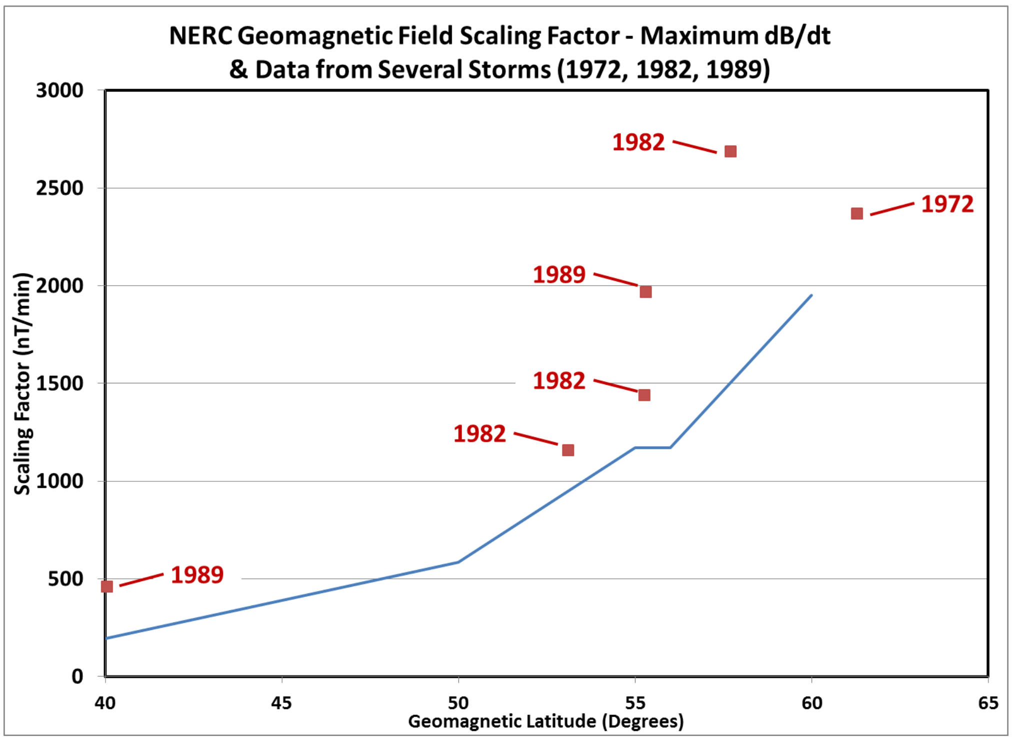

Figure 2 – NERC 100 Year Storm Reference Profile and Observations od dB/dt in 1972, 1982 and 1989 Storms that exceed the NERC Reference Profile

As Figure 2 illustrates that are a number of observations that greatly exceed the NERC reference profile at all geomagnetic latitudes in just these three storms alone. The geomagnetic storm process in part is driven by ionospheric electrojet current enhancements which expand to lower latitudes for more severe storms. The NERC Reference profile precludes that reality by confining the most extreme portion of the storm environment to a 60^{o} latitude with sharp falloffs further south. This NERC profile will not agree with the reality of the most extreme storm events. The excursions above the NERC profile boundary as displayed in Figure 2 clearly points out these contradictions.

In terms of what this implies for the North American region, a series of figures have been developed to illustrate the NERC reference field levels at various latitudes and actual observations that exceed the NERC reference thresholds. Figure 3 provides a plot showing via a red line the ~55^{o} geomagnetic latitude across North America which extends approximately across the US/Canada border. Along this boundary, the NERC Reference profile sets the Peak disturbance threshold at 1170 nT/min, but when considering the three storms not included in the NERC statistics database, it is clear that peaks of ~2700 nT/min have been observed at these high latitudes over just the past ~40 years. As will be discussed later, it is also understood that extremes up to ~5000 nT/min can occur down to these latitudes. Figure 4 provides a similar map showing the boundary at 53^{o} geomagnetic latitude across the US and per the NERC Reference profile, the peak threat level would be limited to 936 nT/min. Yet at this same latitude at the Camp Douglas Station geomagnetic observatory, a peak dB/dt of ~1200 nT/min was observed during the July 1982 storm. Figure 5 provides a map showing the boundary at 40^{o} geomagnetic latitudes and the NERC Reference peak at this location of only 195 nT/min. This figure also notes that in the March 1989 storm the Bay St. Louis observatory observed a peak dB/dt of 460 nT/min, this is 235% larger than the NERC peak threshold.

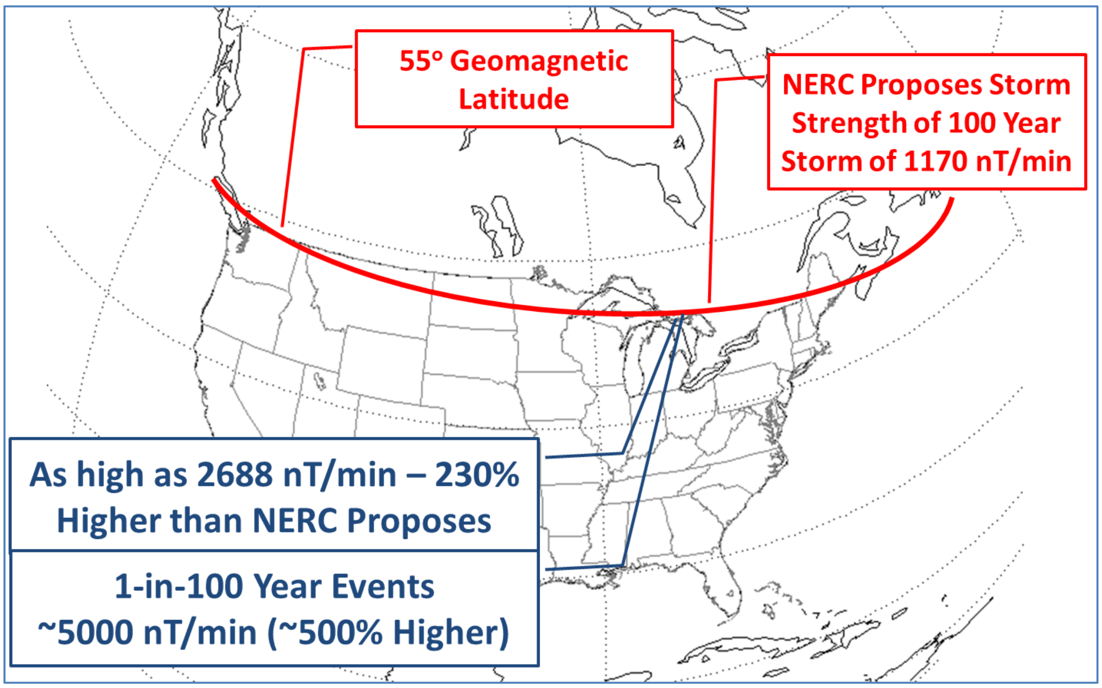

Figure 3 – Comparison of NERC Peak at 55^{o} Latitude versus Actual Observed dB/dt

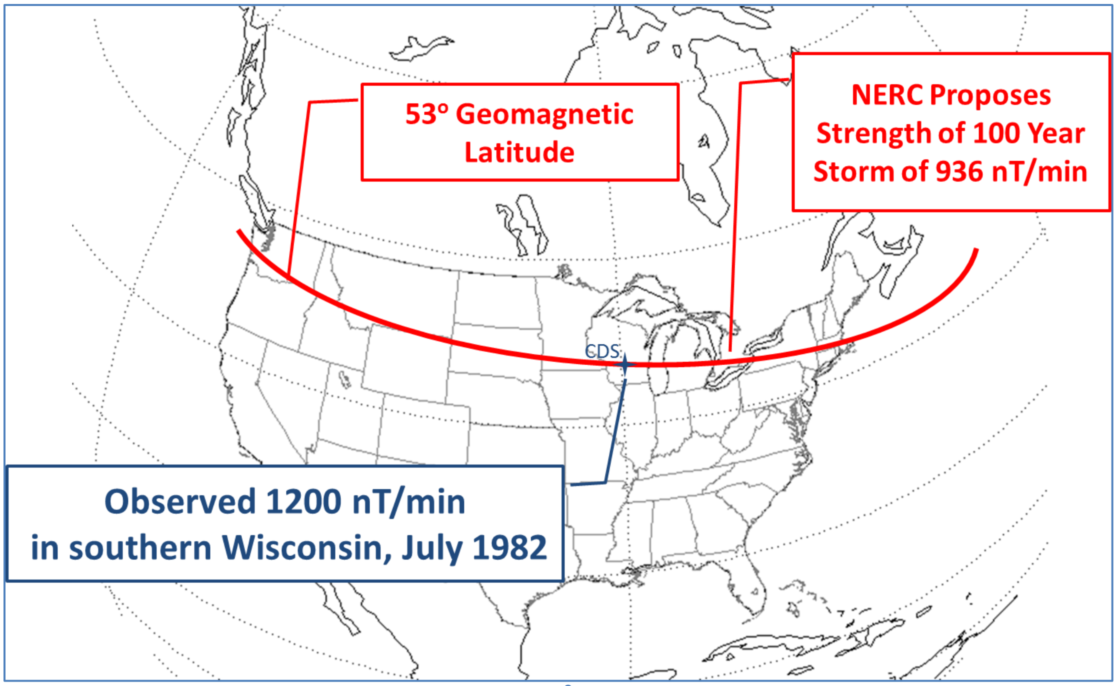

Figure 4 - Comparison of NERC Peak at 53° Latitude versus Actual Observed dB/dt

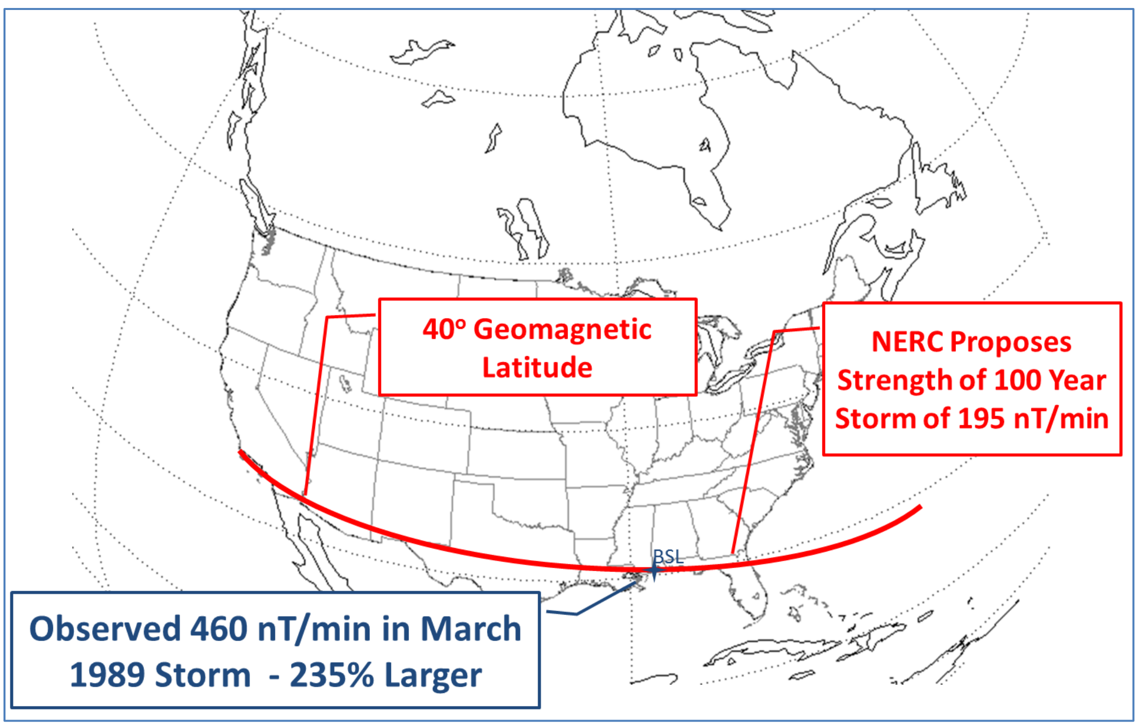

Figure 5 - Comparison of NERC Peak at 40° Latitude versus Actual Observed dB/dt

In summary, these storm observations limited to just three specific storms which happen to fall outside the NERC statistical database all show observations which exceed the NERC Reference profile at all latitudes. This illustrates that the NERC Reference profile cannot be a 1 in 100 year storm reference waveform and is not conservative. It should also be noted that even these three storm events are not representative of the worst case scenarios. In an analysis limited to European geomagnetic observatories, a science team publication concludes “there is a marked maximum in estimated extreme

levels between about 53 and 62 degrees north" and that "horizontal field changes may reach 1000-4000 nT/minute, in one magnetic storm once every 100 years"[4]. One advantage of this European analysis, it did not exclude data from older storms like the March 1989 and July 1982 storms, unlike in the case of the NERC database statistical analysis. In another publication the data from the May 1921 storm is assessed with the following findings; "In extreme scenarios available data suggests that disturbance levels as high as ~5000 nT/min may have occurred during the great geomagnetic storm of May 1921"[5]. In another recent publication, the authors conclude the following in regards to the lower latitude expansion of peak disturbance intensity; "It has been established that the latitude threshold boundary is located at about 50–55 of MLAT"[6]. It should be noted that one of the co-authors of this paper is also a member of the NERC Standards drafting team. All of these assessments are in general agreement and all call into question the NERC Reference Profile. Figure 6 provides a comparison plot of these published results with respect to the NERC Draft Standard profile and illustrates the significant degree of inadequacy the NERC Reference profile provides compared to these estimates of 100 Year storm extremes.

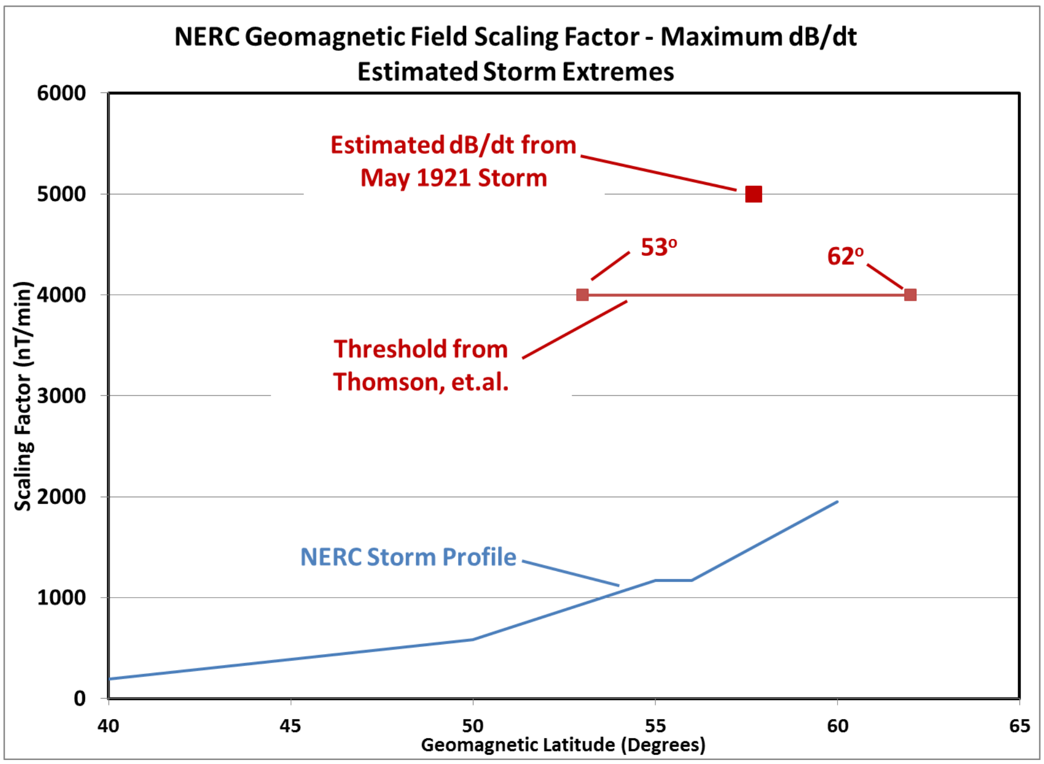

Figure 6 – Scientific Estimates of Extreme Geomagnetic Storm Thresholds compared to Propose3d NERC Draft Standard Profile

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[4] Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, Space Weather, 9, S10001, doi:10.1029/2011SW000696, 2011.

[5] John G. Kappenman, Great Geomagnetic Storms and Extreme Impulsive Geomagnetic Field Disturbance Events – An Analysis of Observational Evidence including the Great Storm of May 1921, Advances in Space Research, August 2005 doi:10.1016/j.asr.2005.08.055

[6] Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, Space Weather, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013.

Discussion of Inadequate Geo-Electric Field Peak Intensity

As the prior section of this discussion illustrates, the Peak Intensity of the proposed NERC geomagnetic disturbance reference field greatly understates a 100 year storm event. In prior comments submitted, it was also discovered that the geo-electric field models that NERC has proposed will also understate the peak geo-electric field[7]. In developing the Peak Geo-electric field, NERC has proposed the following formula:

$$E_{peak} = 8 \times \alpha \times \beta \ (V/km)$$

Figure 7 – NERC Peak Geo-Electric Field Formula

As discussed in the last section of these comments the α (Alpha) factor in the above formula is understated at all latitudes for the NERC 100 year storm thresholds. In addition, the White Paper illustrates that the NERC proposed β (Beta) factor will also understate the geo-electric field by as much as a factor of 5 times the actual geo-electric field. When these two factors are included and multiplied together in the same formula, this acts to compound the individual understatements of the α and β factors into a significantly larger understatement of Peak Geo-electric field.

This compounding of errors in the α and β factors can be best illustrated from a case study provided in the Kappenman/Radasky White Paper. In this paper, Figure 27 (page 26) provides the geo-electric field recorded at Tillamook Oregon during the Oct 30, 2003 storm. Also shown is the NERC Model calculation for the same storm at this location. As this comparison illustrates, the NERC model understates the actual geo-electric field by a factor of ~5 and that the actual peak geo-electric field during this storm is nearly 1.2 V/km. Further this geo-electric field is being driven by dB/dt intensity at Victoria (about 250km north from Tillamook) that is 150 nT/min. Tillamook is also at ~50 geomagnetic latitude, so it is possible that the 100 year storm intensity could reach 5000 nT/min or certainly much higher than 150 nT/min. When using the NERC formula to calculate the peak Geo-electric field at Tillamook, the following factors would be utilized as specified in the NERC draft standard: For Tillamook Location, the α Alpha Factor = 0.3 based on Tillamook being at ~50 degrees MagLat, the β Beta Factor = 0.62 for PB1 Ground Model at Tillamook. Then using the NERC formula the derived Epeak would be:

"Tillamook Epeak" = 8 x 0.3 x 0.62 = 1.488 V/km (from NERC Epeak Formula)

In comparison to the ~1.2 V/km observed during the Oct 2003 storm, this NERC-derived Peak is nearly at the same intensity as caused by a ~150 nT/min disturbance. The scientifically sound method of deriving the Peak intensity is to utilize Faraday's Law of Induction to estimate the peak at higher dB/dt intensities. Faraday's Law of Induction is Linear (assuming the same spectral content for the disturbance field), which requires that as dB/dt increases, the resulting Geo-Electric Field also increases linearly. Therefore using the assumption of a uniform spectral content, which may be understating the threat environment, extrapolating to a 5000 nT/min peak environment would project a Peak Geo-Electric Field of ~40 V/km, a Factor of ~30 times higher than derived from the NERC Epeak Formula[8].

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[7] John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.

[8] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/150) = 33.3, Peak Electric = 1.2 V/km *33.3 = 40 V/km

A similar derivation can be performed for the GIC and geo-electric field observations at Chester Maine in the White Paper. From Figure 14 (page 17) the dB/dt in the Chester region reached a peak of ~600 nT/min and resulted in a ~2V/km peak geo-electric field during the May 4, 1998 storm. For this case study, the proposed NERC standard and the formula for the Peak Geo-Electric Field using the following factors for the Chester location, the Alpha Factor = 0.6 based on Chester being at ~55^{o} MagLat, the Beta Factor = 0.81 for NE1 Ground Model at Chester. The NERC Formula would derive the Peak being only ~3.88 V/km.

"Chester Epeak" = 8 x 0.6 x 0.81 = 3.88 V/km (from NERC Epeak Formula)

In contrast to the NERC Epeak value, a physics-based calculation can be made for the case study of the May 4, 1998 storm at Chester. Again, Faraday's Law of Induction can be utilized to extrapolate from the observed 600 nT/min levels to a 5000 nT/min threshold. This results in a Peak Geo-Electric Field of ~16.6 V/km, a Factor of ~4.3 higher than derived from the NERC Formula[9].

Discussion of Data-Based GMD Standard to Replace NERC Draft Standard

As prior sections of this discussion has revealed, the proposed NERC Draft Standard does not accurately describe the threat environment consistent with a 1-in-100 Year Storm threshold, rather the NERC Draft Standard proposes storm thresholds that are only a 1-in-10 to 1-in-30 Year frequency of occurrence. Further, the methods proposed by NERC to estimate geo-electric field levels across the US are not validated and where independent assessment has been performed the NERC Geo-Electric Field levels are 2 to 5 times smaller than observed based on direct GIC measurements of the power grid.

Basic input assumptions on ground conductivity used in the NERC ground modeling approach have never been verified or validated. Ground models are enormously difficult to characterize, in that for the frequencies of geomagnetic field disturbances, it is necessary to estimate these profiles to depths of 400kM or deeper. Direct measurements at these depths are not possible to carry out and the conductivity of various rock strata can vary by as much as 200,000%, creating enormous input modeling uncertainties for these ground profiles. Further it has been shown that the NERC geo-electric field modeling calculations themselves appear to have inherent frequency cutoff's that produce underestimates of geo-electric fields as the disturbance increases in intensity and therefore importance. Hence the NERC Standard is built entirely upon flawed assumptions and has no validations.

A framework for a better Standard which is highly validated and accurate has been provided via the Kappenman/Radasky White Paper and the discussion provided in these comments. As noted in the White Paper, the availability of GIC data and corresponding geomagnetic field disturbance data allowed highly refined estimates to be performed for geo-electric fields and to extrapolate the Geo-Electric Field to the 100 Year storm thresholds for these regions. The primary inputs (other than GIC and corresponding geomagnetic field observations) are simply just details on the power grid circuit parameters and circuit topology. These parameters are also known to very high precision (for example transmission line resistance is known to 4 significant digits after the decimal point). Asset locations are

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[9] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/600) = 8.3, Peak Electric = 2 V/km *8.3 = 16.6 V/km

also known with high precision and many commercially available simulation tools can readily compute the GIC for a uniform 1 V/km geo-electric field. This calculation provides an intrinsic GIC flow benchmark that can be used to convert any observed GIC to an regionally valid Geo-Electric Field that produced that GIC. Further this calculation is derived over meso-scale distances on the actual power grid assets of concern. As summarized in a recent IEEE Panel discussion, this approach allows for wide area estimates of ground response than possible from conventional magneto-telluric measurements[10]. Figure 8 provides a map showing the locations of the Chester, Seabrook and Tillamook GIC observations and the approximate boundaries based upon circuit parameters of the ground region that were validated.

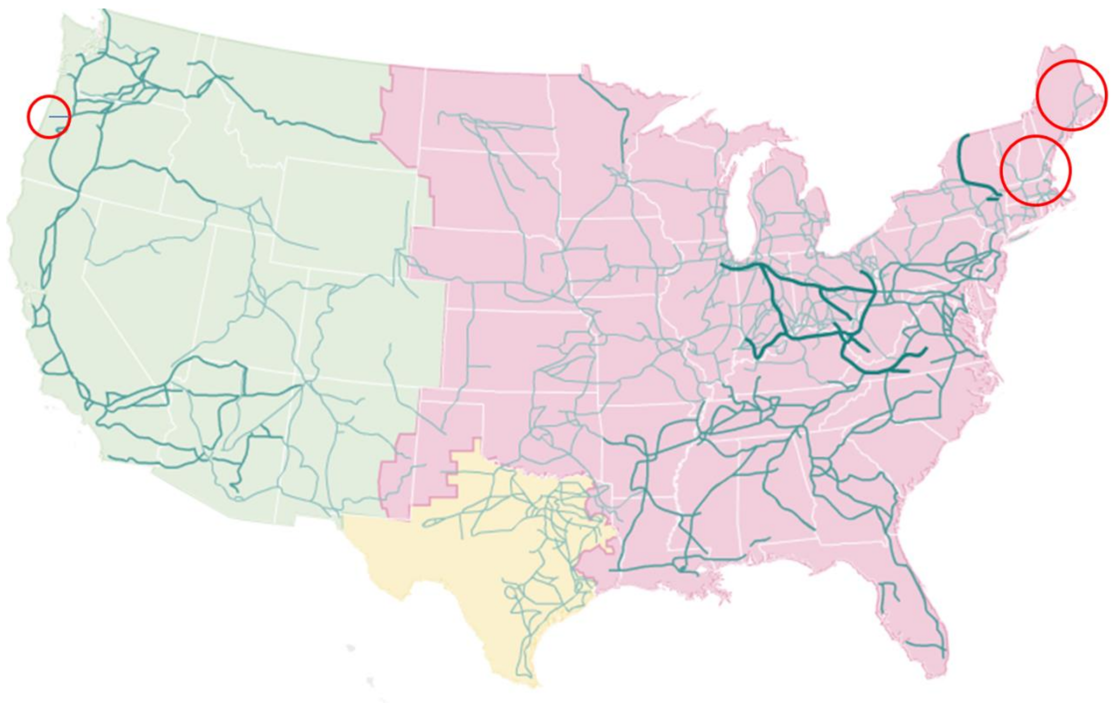

Figure 8 – Red Circles provide Region of Ground Model Validation using GIC observations from Kappenman/Radasky White Paper.

As filed in a recent FERC Docket filing[11], ~100 GIC monitoring sites have operated and are collecting data across the US. Using these analysis techniques and the full complement of GIC monitoring locations, it is possible to accurately benchmark major portions of the US as shown in the map in Figure 9. As shown in this figure, the bulk of the Eastern grid is covered and in many locations with overlapping benchmark regions, such that multiple independent observations can be used to confirm the accuracy of the regional validations. The same is also true for much of the Pacific NW. As noted in Meta-R-319 and shown below is Figure 10 from that report, these two regions are the most at-risk regions of the US Grid.

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[10] Kappenman, J.G., "An Overview of Geomagnetic Storm Impacts and the Role of Monitoring and Situational Awareness", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[11] Foundation for Resilient Societies, "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND", Docket No. RM14-1-000, submitted to FERC on August 18, 2014.

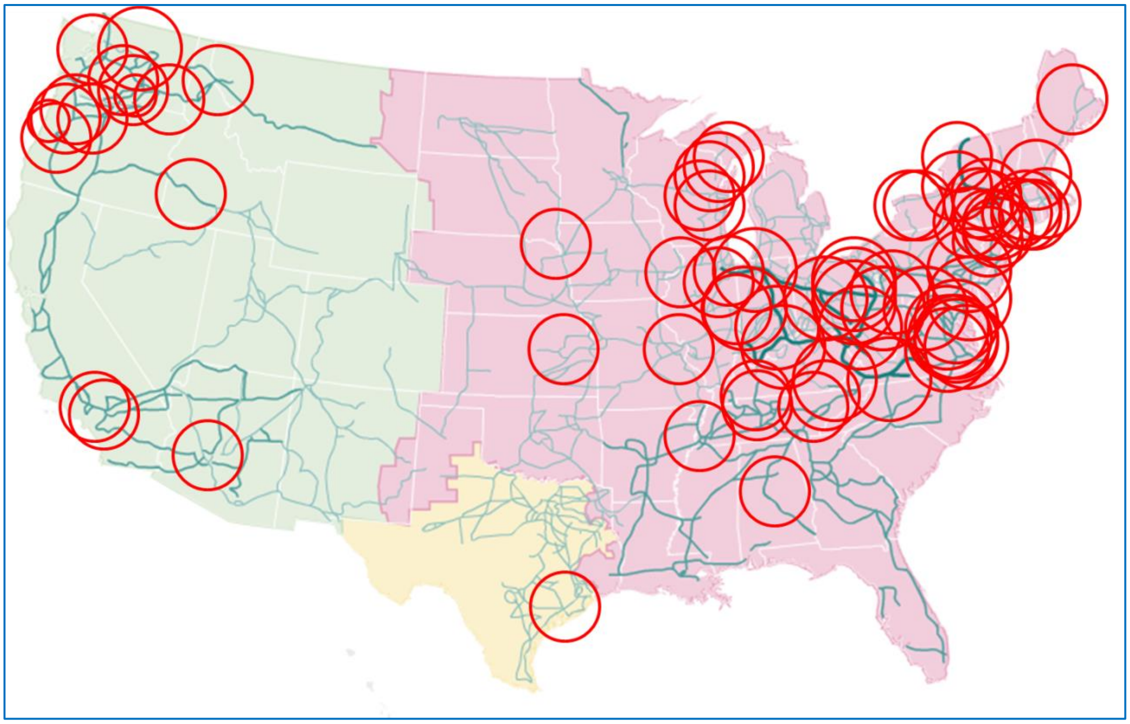


Figure 9 – GIC Observatories and US Grid-wide validation regions.

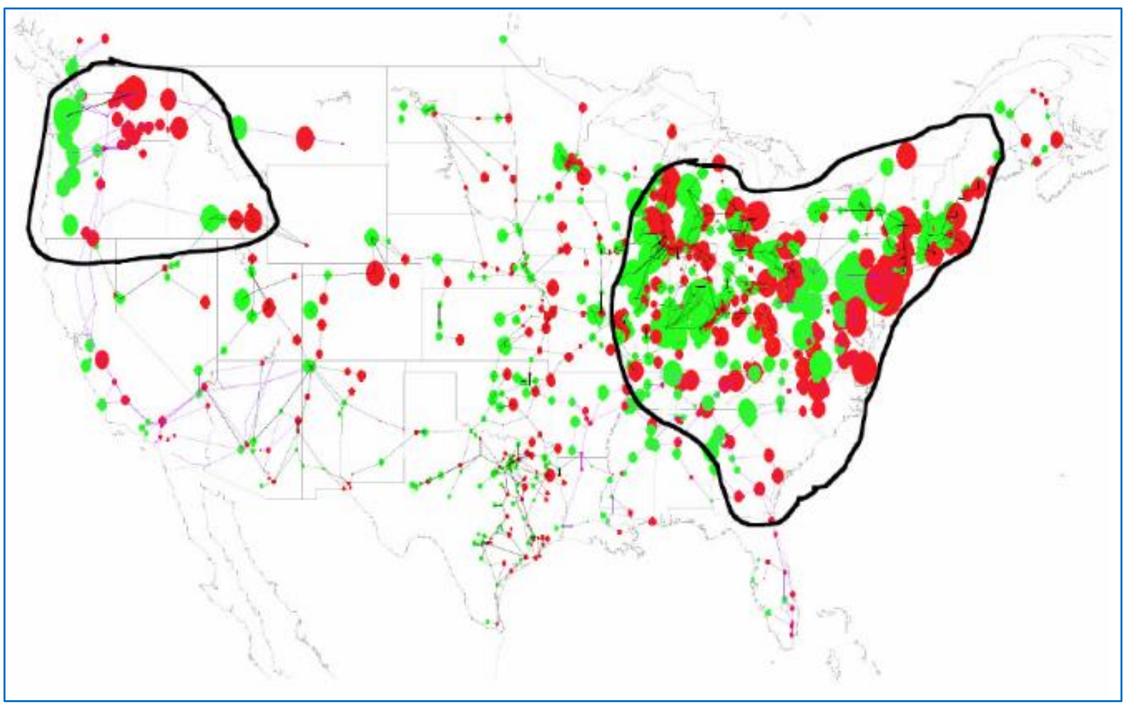


Figure 10 – Map of At-Risk Regions from Meta-R-319 Report for 50^{o} Severe Storm Scenario

Each of these GIC measurements can define and validate the geo-electric field parameters over considerable distance. In the example of the Chester Maine case study, the validations in the case of the 345kV system can extend ~ 250kM radius. At higher kV ratings, the footprint of GIC and associated geo-electric field measurements integrates over an even larger area. As these measurements are accumulated over the US, the characterizations provide a very complete coverage with many

overlapping coverage confirmations. These confirmations will also have Ohm's law degree of accuracy, whereas magnetotelluric observations can still have greater than factor of 2 uncertainty[12]. For those areas where perhaps a GIC observation is not available, this region can utilize a base intensity level that agrees with neighboring systems until measurements can be made available to fully validate the regional characteristics.

This Observational-Based Standard further establishes a more accurate framework for developing the standard using facts-based GIC observation data as well as the laws of physics[13], and removes the dependence on simulation models which could be in error. The power system and GIC flows observed on this system will always obey the laws of physics while models may exhibit erratic behaviors and are dependent on the skill/qualifications of the modeler and the uncertainty of model inputs. Models are always inferior to actual data as they cannot incorporate all of the factors involved and can have biases which can inadvertently introduce errors. This Observational Framework methodology is also open and transparent so any and all interested parties can review and audit findings. The validations can be performed quickly and inexpensively across all of these observational regions. It also allows for simple updates once new transmission changes are made over time as well.

Respectfully Submitted by,

John Kappenman, Principal Consultant
Storm Analysis Consultants

Curtis Birnbach, President and CTO
Advanced Fusion Systems

[12] Boteler, D., "The Influence of Earth Conductivity Structure on the Electric Fields that drive GIC in Power Systems", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[13] For example, Ohm's Law and Faraday's Law of Induction

Comments on NERC TPL – 007 – 1 (R5)

Reference s*creening criterion for GIC Transformer Thermal Impact Assessment*

Issue

A level of 15 Amps / phase was selected for this screening. It was based on temperature rise measurements of structural parts of some core form transformers reaching a level of 50 K upon application of 15 Amps / phase DC.

Comment – 1

Since the time constant of the transformer structural parts is typically in the 10 – minute range, these temperatures were reached after application of the DC current for 10's of minutes (up to 50 minutes in some cases). The high level GIC pulses are typically of much shorter duration and the corresponding temperature rise would be a fraction of these temperature rises.

Recommendation

Upon performing temperature calculations of the cases referenced in the NERC screening White paper for GIC pulses, we suggest the following:

1. The 15 Amps / phase could be kept as a screening criterion for GIC levels extending over; say, 30 minutes.
2. A higher level of 50 Amps / phase is used as a screening criterion for high – peak, short – duration pulses. A 3 – minute duration of 50 Amps would be equivalent to, and even more conservative than, the 15 Amps / phase steady state.

Comment – 2

The 15 Amps / phase level was based on measurements on transformers with core – types, other than 3 – phase, 3 – limb cores. Three Phase core form transformers with 3 – limb cores are less susceptible to core saturation.

Recommendation

We suggest that, for 3 – phase core form transformers with 3 – limb cores, a higher level of GIC, for example 30 or 50 Amps / phase, is selected for the screening level for the base GIC and correspondingly

a much higher level, for example, 100 Amps / phase, for the high – peak, short – duration GIC pulses.

Note 1:

The revised screening criterion recommended in the above, is not only more appropriate technically than what is presently suggested in the NERC "Thermal screening" document, but also will reduce the number of transformers to be thermally assessed probably by a factor of 10; which would make the thermal evaluation of the $\geq$ 200 kV transformer fleet in North America to be more feasible to be done in the time period required by the NERC document.

Note 2:

It is to be noted that proposing one value of GIC current for screening for all transformer types (core form vs. shell form), sizes, designs, construction, etc. is not technically correct. However, for the sake of moving the NERC document forward, we agreed to follow the same path but provide the improved criterion we recommended above.

Submitted by:

Mr. Raj Ahuja, Waukesha
Mr. Mohamed Diaby, Efacec
Dr. Ramsis Girgis, ABB
Mr. Sanjay Patel, Smit
Mr. Johannes Raith, Siemens

Comments on NERC TPL – 007 – 1 (R6)

"GIC Transformer Thermal Impact Assessment"

Issue

The document should have a Standard GIC signature to be used for the thermal impact Assessment of the power Transformer fleet covered by the NERC document.

Comment – 1

Users would not be able to predict, to any degree of accuracy, what GIC signature a transformer would be subjected to during future GMD storms. This is since the actual GIC signature will depend on the specific parameters and location of the future GMD storms. Unless a user requires thermal assessment of their fleet of transformers to actual GIC signatures, the user should be able to use a Standard GIC Signature; where the parameters of the signature (magnitudes and durations of the different parts of the signature) would be specified by the user.

This is parallel to the standard signatures used by the transformer / utility industry Standards (IEEE & IEC) for lightning surges, switching surges, etc.; where standard signatures (wave – shapes) are used for evaluating the dielectric capability of transformers.

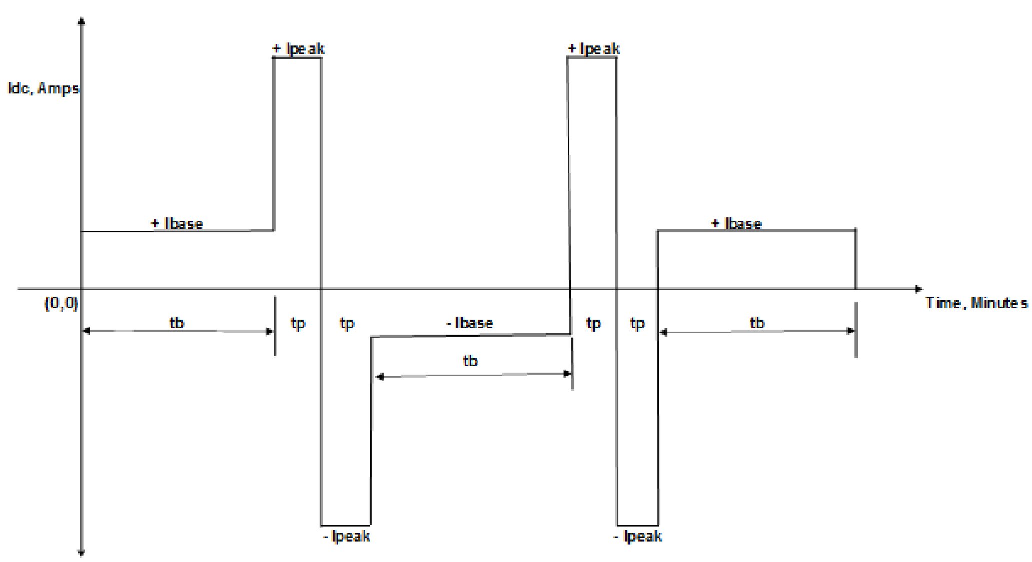
Recommendation

We recommend that the NERC document suggest using the Standard GIC signature, proposed in the upcoming IEEE Std. PC57.163 GIC Guide, shown below. This signature was based on observation / study of a number of signatures of measured GIC currents on a number of power transformers located in different areas of the country. It was recognized that GIC current signatures can be generally characterized by a large number of consecutive narrow pulses of low – to – medium levels over a period of hours interrupted by high peaks of less than a minute, to several minutes, duration. Therefore, GIC signatures are made of two main stages of GIC; namely:

- Base Stage: Consists of multiples of small – to – moderate magnitudes of GIC current sustained for periods that could be as short as a fraction of an hour to several hours.
- Peak GIC Pulse Stage: Consists of high levels of GIC pulses of durations of a fraction of a minute to several minutes.

Utilities would provide values of the Base GIC (I_{base}) current and the Peak GIC current pulses (I_{peak}) specific to their power transformers on their respective power system. These two parameters are to be determined based on the geographic location of the transformer as well as the part of the power grid the transformer belongs to. For standardization purposes, the time durations of the base GIC and GIC pulses; t_b and t_p, respectively, can be fixed at 20 minutes and 3 minutes; respectively. Also, the full duration of the high level GMD event can be standardized to be 2 or 3 hours long; encompassing several cycles of the GIC signature. These parameters can be as conservative as they need to be.

Specifying a Standard GIC signature for the thermal Assessment of the thousands of power Transformers covered by the NERC document would allow using generic / simplified (but sufficiently accurate) thermal models for the thermal Assessment and, hence, a significantly less effort. On the other hand, the thermal Assessment of transformers, to be done correctly, for different more complex GIC signatures, would require much more time to complete.



Submitted by:

Mr. Raj Ahuja, Waukesha
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EIS Council Comments on Benchmark GMD Event

TPL-007-1

Submitted on October 10, 2014

Introduction

The Electric Infrastructure Security Council's mission is to work in partnership with government and corporate stakeholders to host national and international education, planning and communication initiatives to help improve infrastructure protection against electromagnetic threats (e-threats) and other hazards. E-threats include naturally occurring geomagnetic disturbances (GMD), high-altitude electromagnetic pulses (HEMP) from nuclear weapons, and non-nuclear EMP from intentional electromagnetic interference (IEMI) devices.

In working to achieve these goals, EIS Council is open to all approaches, but feels that industry-driven standards, as represented by the NERC process, are generally preferable to government regulation. That said, government regulation has proven necessary in instances (of all kinds) when a given private sector industry does not self-regulate to levels of safety or security acceptable to the public. EIS Council is concerned that the new proposed GMD benchmark event represents an estimate that is too optimistic, and would invite further regulatory scrutiny of the electric power industry.

The proposed benchmark GMD event represents a departure from previous GMDTF discussions, where the development of the "100-year" benchmark GMD event appeared to be coming to a consensus, based upon statistical projections of recorded smaller GMD events to 100-year storm levels. These levels of 10 – 50 V/km, with the average found to be 20 V/km, were also in agreement with what were thought to be the storm intensity levels of the 1921 Railroad Storm, which, along with the 1859 Carrington Event, were typically thought to be the scale of events for which the NERC GMDTF was formed to consider.

The new approach described in April 14, 2014 Draft (and subsequent GMDTF meetings and discussions) contains several key features that EIS Council does not consider to yet have enough scientific rigor to be supported, and would therefore recommend that a more conservative or "pessimistic" approach should be used to ensure proper engineering safety margins for electric grid resilience under GMD conditions. These are:

1. The introduction of a new "spatial averaging" technique, which has the effect of lowing the benchmark field strengths of concern from 20 V/km to 8 V/km;

2. A lack of validation of this new model, demonstrating that it is in line with prior observed geoelectric field values;

3. The use of the 1989 Quebec GMD event as the benchmark reference storm, rather than a larger known storm such as the 1921 Railroad storm;

4. The use of 60 degrees geomagnetic latitude as the storm center; and

5. The use of geomagnetic latitude scaling factors to calculate expected storm intensities south of 60 degrees.

Spatial Averaging and Model Validation

The introduction of the spatial averaging technique is a novel introduction to discussions of the GMDTF. While the concept could prove to have validity, the abrupt change to a new methodology at this time is not fully understood by the GMDTF membership, nor has it yet had any peer review by the larger space weather scientific community. In order to ensure confidence that this is a proper approach, it is necessary that this approach be validated with available data via the standard peer-review process.

Prior findings of the GMDTF of a 20 V/km peak field values were shown to be in line with prior benchmark storms such as the 1921 Railroad storm, for which there is very good magnetometer data across the United States and Canada. Even for the 1989 Quebec Storm, on which this new benchmark is supposed to be based, it is not clear whether the new spatial averaging technique has been demonstrated to be in line with the known magnetometer data. This would seem to be a fairly straightforward validation of this new model, but is currently lacking in the description of the new approach.

The spatial averaging method also appears to be at odds with standard engineering safety margin design approaches. As an example, if the maximum load for a bridge is 20 tons, but the average load is 8 tons, a bridge is designed to hold at least 20 tons, or more typically 40 tons, a factor of two safety margin over the reasonably expected maximum load. It is recommended that the screening criteria be increased to encompass the maximum credible storm event, rather than an average, in line with typically accepted best practices for engineering design.

The description of the method does describe that within the expected spatially-averaged GMD event of 8 V/km, that smaller, moving "hot spots" of 20 V/km are expected. It therefore seems prudent for electric power companies to analyze the expected resilience of their system against a 20 V/km geoelectric field, as any given company could find themselves within such a "hot spot" during a GMD event.

One further point to consider is that, while the GMDTF scope does not at present include EMP, the unclassified IEC standard for the geoelectric fields associated with EMP E3 is 40 V/km. Should the scope of the GMDTF or FERC order 779 ever be expanded to include EMP E3, 40 V/km is the accepted international standard, something to consider when setting the benchmark event, as any given power company could find themselves subject to the maximum credible EMP E3 field.

1989 Quebec Storm as the Benchmark Event

The 1989 Quebec Storm is very well-studied event, and is a dramatic example of the impacts of GMD on power grids. The loss of power in the Province of Quebec, failure of the Salem transformer, and other grid anomalies associated with the storm are all well documented. The GMDTF was formed, and FERC Order 779 issued, to ensure grid resilience for events that will be much larger than the 1989 Quebec Storm, such as the 1921 Railroad Storm. The two figures below show a side-by-side comparison of the 1989 and 1921 storms. The geographic size, and also the latitude locations are quite striking.

The use of the 1989 Quebec Storm as the benchmark event is of concern because simply scaling the field strengths of the 1989 Storm higher (an "intensification factor" of 2.5 is used), but leaving the same geographic footprint, does not appear to be a valid approach. While the 2.5 scaling factor is described to produce local "hot spots" of 20 V/km, in agreement with earlier findings, it fails to consider the well-known GMD phenomena that the electrojets of larger storms shift southward, as can be seen in comparing the two figures. By using the geographic footprint of the 1989 storm, the new benchmark will predict geoelectric field levels that are incorrect for geomagnetic latitudes below 60 degrees, where the center of the new benchmark storm has been set.

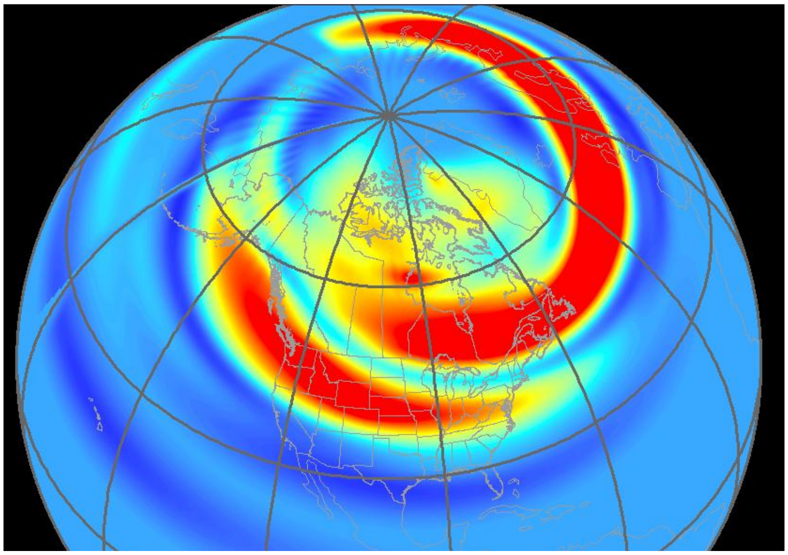

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

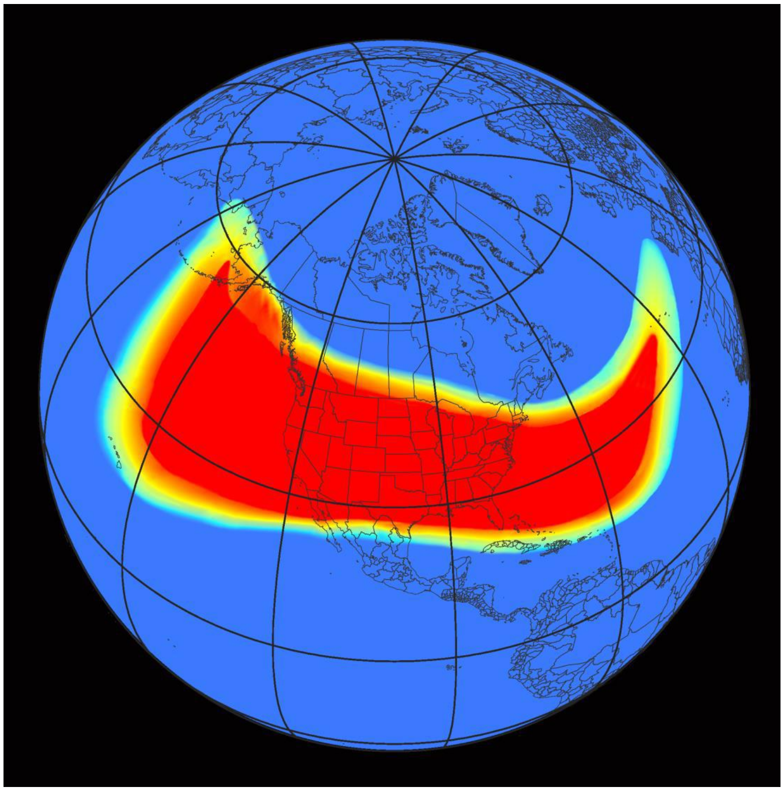

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

As the figures above show, GMD events larger than the 1989 Quebec event are expected to be larger in overall geographic laydown (continental to global in scale), and also to be centered at lower geomagnetic latitudes than the 1989 storm, due to a southward shifting of the auroral electrojet for more energetic storms. While the latitudinal scaling factor α may be correct for a storm like the 1989 Storm and centered on 60 degrees geomagnetic latitude, use of these scaling factors does not appear to be valid for GMD events where the storm will be centered at a lower latitude, and have a larger geographic footprint. While the β factor - which captures differences in geologic ground conductivity - will remain valid under all storm scenarios, the α factors would only be valid for a storm centered at 60 degrees. For example, in looking at figure 2 above, the storm is quite large, and centered at (roughly) 40 – 45 degrees North Latitude. The correct α factor for 45 degrees in this case would be 1, rather than the 0.2 value that would be correct for a storm centered at 60 degrees North Latitude. As it is not known what the center latitude of any given storm center would be, it would seem that the use of the 60 degree storm center latitude and subsequent α scaling factors is not fully supported.

Supporting scientific evidence for the use of the 60-degree storm center and scaling factors is cited in TPL-007-1. The supporting paper by Ngwira et al[1], however, discusses a "latitude threshold boundary [that] is associated with the movements of the auroral oval and the corresponding auroral electrojet current system." The latitude boundary found in the paper, however, is given as 50 degrees magnetic latitude, rather than 60 degrees. The study determines this boundary based on observations of ~30 years of geomagnetic storm data. While the data set is large, it does not contain very large storms, on the scale of the 1921 Railroad storm. As the largest storms are known to have the largest southward electrojets shifts, it would seem prudent that the benchmark be adjusted to be consistent with the supporting scientific finding of 50 degrees magnetic latitude, and a subsequent re-calculation of the α scaling factors for latitudes below 50 degrees.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed

[1] Ngwira, Pulkkinen, Wilder, and Crowley, *Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications*, Space Weather, Vol. 11 121-131 (2013)

discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there would seem to be a scientific inconsistency in using a benchmark storm centered at 60 degrees geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location down to 50 degrees, as cited in the supporting document. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, centered at the cited 50 degree magnetic latitude threshold boundary, with subsequently updated latitude scaling factors for lower latitudes, as the benchmark event against which the individual electric power companies can analyze their system resilience.

Response to NERC Request for Comments on TPL-007-1

Comments Submitted by the Foundation for Resilient Societies
October 10, 2014

The Benchmark Geomagnetic Disturbance (GMD) Event whitepaper authored by the NERC Standard Drafting Team proposes a conjecture that geoelectric field "hotspots" take place within areas of 100-200 kilometers across but that these hotspots would not have widespread impact on the interconnected transmission system. Accordingly, the Standard Drafting Team averaged geoelectric field intensities downward to obtain a "spatially averaged geoelectric field amplitude" of 5.77 V/km for a 1-in-100 year solar storm. This spatial averaged amplitude was then used for the basis of the "Benchmark GMD Event."[1]

In this comment, we present data to show the NERC "hotspot" conjecture is inconsistent with real-world observations and the "Benchmark GMD Event" is therefore not scientifically well-founded.[2] Figures 1 and 2 show simultaneous GIC peaks observed at three transformers up to 580 kilometers apart, an exceedingly improbable event if NERC's "hotspot" conjecture were correct.

According to Faraday's Law of induction, geomagnetically induced current (GIC) is driven by changes in magnetic field intensity (dB/dt) in the upper atmosphere. If dB/dt peaks are observed simultaneously many kilometers apart, then it would follow that GIC peaks in transformers would also occur simultaneously many kilometers apart. Figure 3 shows simultaneous dB/dt peaks 1,760 kilometers apart during the May 4, 1988 solar storm.

In summary, the weight of real-world evidence shows the NERC "hotspot" conjecture to be erroneous. Simultaneous GIC impacts on the interconnected transmission system can and do occur over wide areas. The NERC Benchmark GMD Event is scientifically unfounded and should be revised by the Standard Drafting Team.

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[1] See Appendix 1 for excerpts from the "Benchmark Geomagnetic Disturbance Event Description" whitepaper relating to NERC's "spatial averaging" conjecture.

[2] Data compilations in Figures 1 and 2 are derived from the AEP presentation given to the NERC GMD Task Force in February 2013. Figure 3 is derived from comments submitted to NERC in the Kappenman-Radasky Whitepaper.

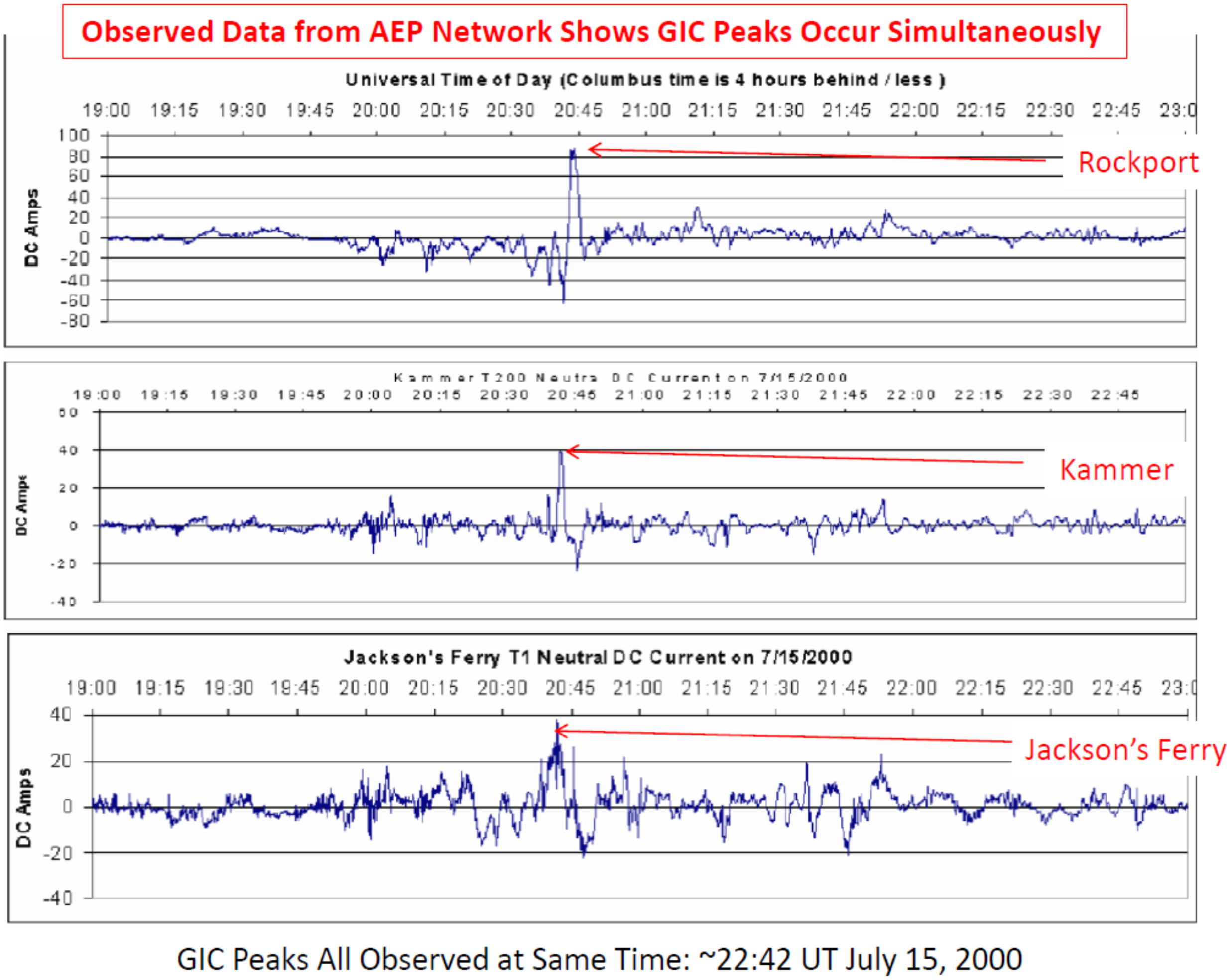


Figure 1. American Electric Power (AEP) Geomagnetically Induced Current Data Presented at February 2013 GMD Task Force Meeting

Locations and Distances for GIC Peaks at Kammer, Jackson's Ferry, and Rockport Transformers
All Peaks Observed Simultaneously at ~22:42 Universal Time on July 15, 2000

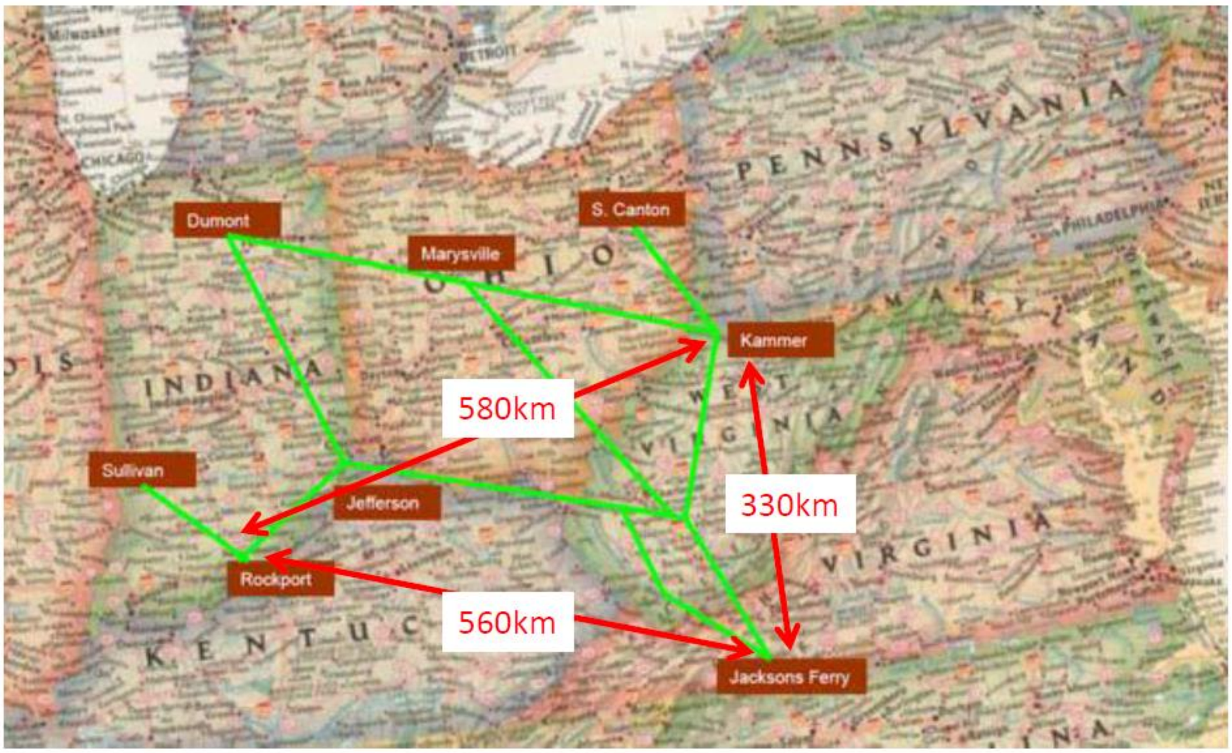


Figure 2. Location of Transformer Substations with GIC Readings on Map of States within AEP Network

Magnetometer Readings from Ottawa and St. John's Observatories During May 4, 1988 Solar Storm Show Simultaneous dB/dt Peaks Far Apart

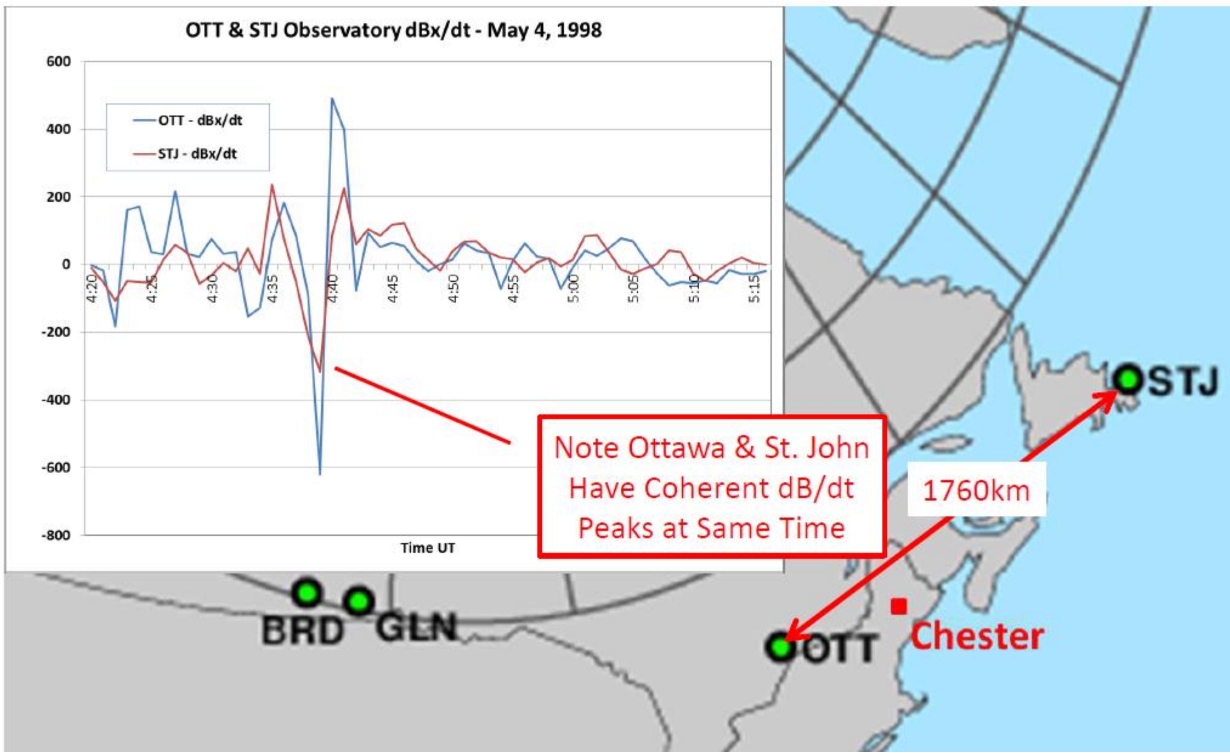


Figure 3. Magnetometer Readings Over Time from Ottawa and St. John Observatories

Appendix 1

Excerpts from
Benchmark Geomagnetic Disturbance Event Description

North American Electric Reliability Corporation

Project 2013-03 GMD Mitigation

Standard Drafting Team

Draft: August 21, 2014

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

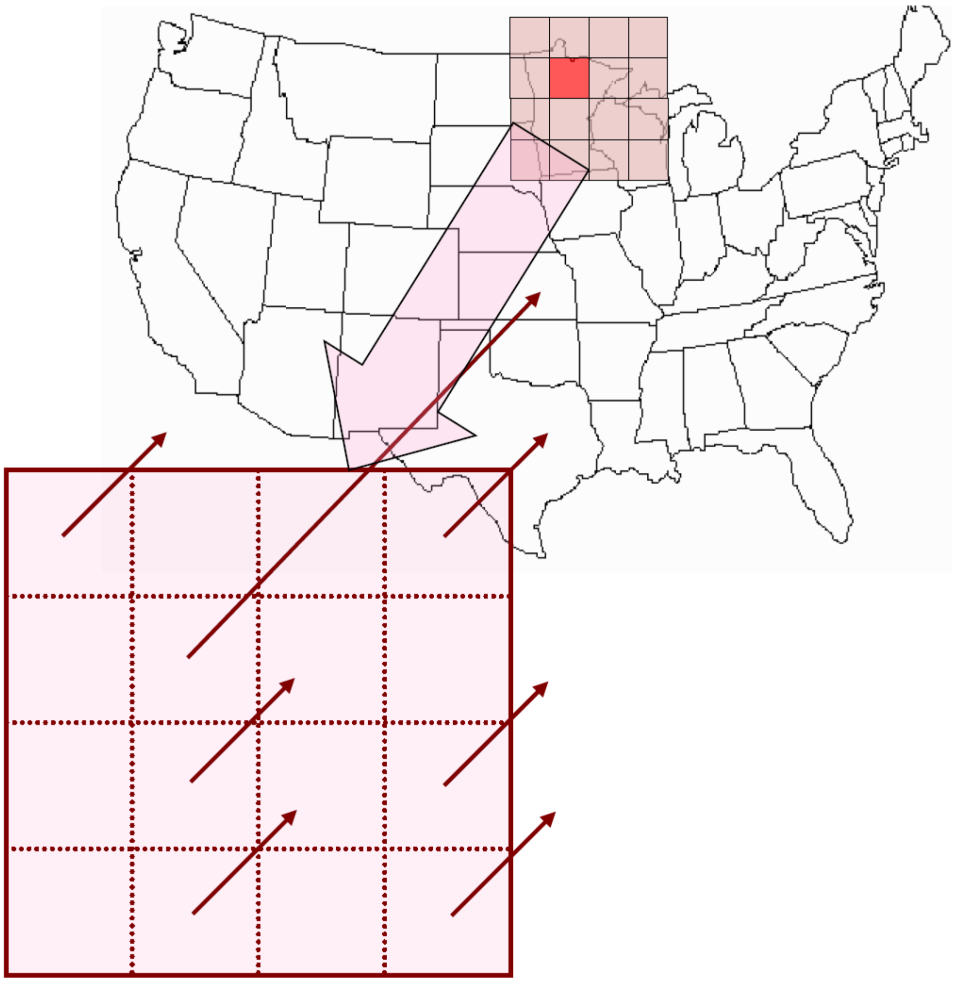


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

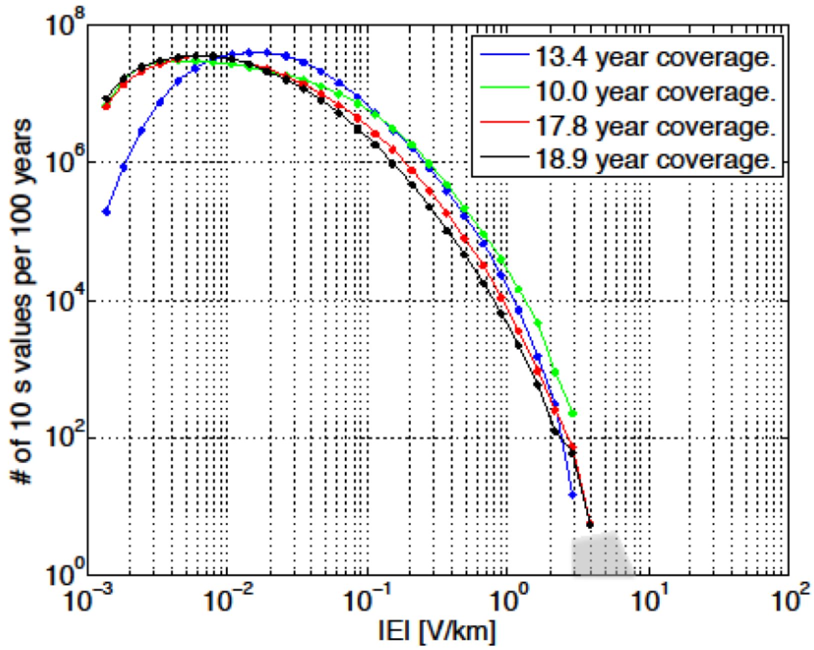


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

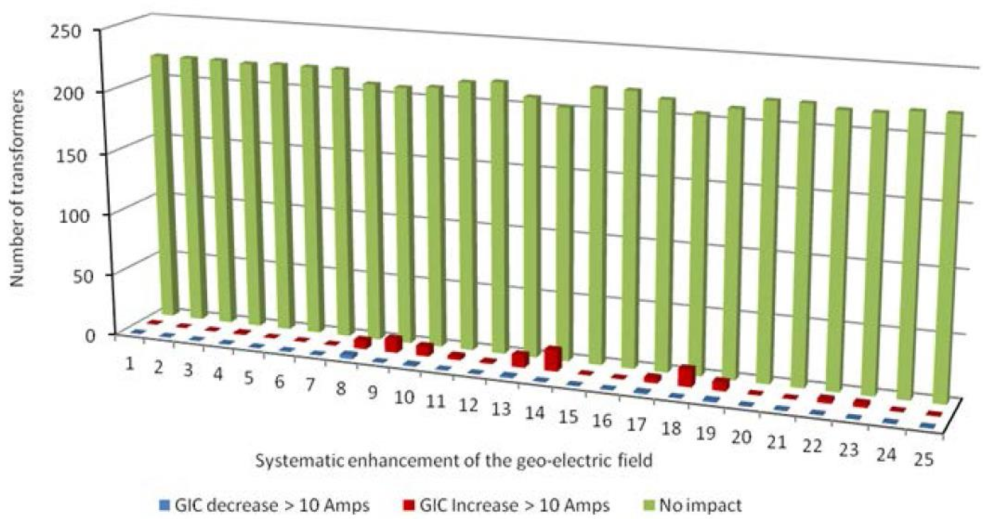


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Mitigation

The Geomagnetic Disturbance (GMD) Mitigation Standard Drafting Team (SDT) thanks all commenters who submitted comments on the standard. Project 2013-03 is developing requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in FERC Order No. 779:

- EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014. This first stage standard in the project will require applicable registered entities to develop and implement Operating Procedures.

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance events is being developed to meet the Stage 2 directives. The proposed standard will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. If the assessments identify potential impacts, the standard(s) will require the registered entity to develop corrective actions to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

TPL-007-1 was posted for a 45-day public comment period from August 27, 2014 through October 10, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 58 sets of comments, including comments from approximately 175 people from companies and organizations representing all 10 Industry Segments as shown in the table on the following pages.

Summary Consideration:
The SDT appreciates the careful review and constructive comments from stakeholders. This active participation is critical to meeting the project scope outlined in the Standard Authorization Request (SAR) and all FERC directives prior to the January 21, 2015 filing deadline.

The drafting team made the following changes to the proposed standard and supporting material:

- Geomagnetically-induced current (GIC) threshold for thermal assessments. The SDT has revised the effective GIC value for applicable Bulk Electric System (BES) power transformers requiring thermal impact assessments from 15 A per phase to 75 A per phase. Justification is provided in the revised Thermal Screening Criterion white paper.

- Transformer thermal impact assessment. The SDT has revised the Transformer Thermal Impact Assessment white paper to include a simplified method for performing a transformer thermal assessment.
- Requirements R1 through R4 contains editorial changes for clarity.
- Requirement R5 has been revised to be consistent with the 75 A per phase GIC threshold for transformer thermal assessments. The planning entity is no longer required to provide GIC time series to all Transmission Owners and Generator Owners, but must do so upon request.
- Requirement R6 has been revised to include the 75 A per phase GIC threshold for transformer thermal assessments.
- Requirement R7 contains editorial changes for clarity.
- Evidence retention periods have been revised.
- The VRF for Requirement R2 has been changed from Medium to High. This change is for consistency with the corresponding requirement in TPL-001-4, which was raised to High in response to FERC directive. (See NERC's filing of dated August 29, 2014 under RM12-1-000)
- Rationale boxes and the Application Guidelines section have been revised to provide additional explanations.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Wayne Sipperly	New York Power Authority	NPCC	5
10.	Mark Kenny	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11. Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
12. Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13. Bruce Metruck	New York Power Authority	NPCC	6
14. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8

				1	2	3	4	5	6	7	8	9	10
2.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
3.	Group	Louis Slade	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton	NERC Compliance Policy	NPCC	5, 6
2. Connie Lowe	NERC Compliance Policy	RFC	5, 6
3. Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
4. Chip Humphrey	Power Generation Compliance	NA - Not Applicable	5
5. Jarad L Morton	Power Generation Compliance	RFC	5
6. Larry Whanger	Power Generation Compliance	SERC	5
7. Larry Nash	Electric Transmission Compliance	SERC	1, 3
8. Jeffrey N Bailey	Nuclear Compliance	NA - Not Applicable	5

				1	2	3	4	5	6	7	8	9	10
4.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
5.	Group	Richard Hoag	FirstEnergy Corp.	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dressner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

6. Richard Hoag	FirstEnergy Corp.	RFC	NA
7. Chris Pilch	FirstEnergy Corp.	RFC	NA
8. Mike Miller	FirstEnergy Corp.	RFC	NA

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	David Greene	SERC Planning Standards Subcommittee										

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren		
2. Phil Kleckley	SCE&G's		
3. Shih-Min Hsu	Southern Company Services		
4. Jim Kelley	PowerSouth		
5. Darrin Church	TVA		
6. David Greene	SERC		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	John Boshears	City Utilities of Springfield	SPP	1, 4
3.	Jerry Bradshaw	City Utilities of Springfield	SPP	1, 4
4.	Derek Brown	Westar Energy	SPP	1, 3, 5, 6
5.	Kevin Foflygen	City Utilities of Springfield	SPP	1, 4
6.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
7.	Jonathan Hayes	Southwest Power Pool	SPP	2
8.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
9.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
10.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
11.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
12.	Shannon Mickens	Southwest Power Pool	SPP	2
13.	James Nail	City of Independence, MO	SPP	3, 5
14.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	NPCC	6
7.			MRO	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Randy Hahn	Ocala Utility Services	FRCC	3
6.	Don Cuevas	Beaches Energy Services	FRCC	1
7.	Stanley Rzad	Keys Energy Services	FRCC	4
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Matt Culverhouse	City of Bartow	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steven Lancaster	Beaches Energy Services	FRCC	3
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Authority	FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy		1
2.	Lee Schuster	Duke Energy		3
3.	Dale Goodwine	Duke Energy		5
4.	Greg Cecil	Duke Energy		6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Bedder	Orange & Rockland Utilities (ORU)	NPCC	NA

Additional Member	Additional Organization	Region	Segment Selection
2. David Burke	Rockland Electric	RFC	NA

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
14.	Group	Phil Hart	Associated Electric Cooperative, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
15.	Group	Greg Campoli	IRC SRC		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Cheryl Moseley	ERCOT	ERCOT	2
2. Ben Li	IESO	NPCC	2
3. Matt Goldberg	NEISO	NPCC	2
4. Charles Yeung	SPP	SPP	2
5. Ali Miremadi	CAISO	WECC	2
6. Terry Bilke	MISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
16.	Group	Peter A. Heidrich	FRCC GMD Task Force										X

Additional Member	Additional Organization	Region	Segment Selection
1. Carol Chinn	Florida Municipal Power Agency	FRCC	3, 4, 5, 6
2. Carl Turner	Florida Municipal Power Agency	FRCC	3, 4, 5, 6
3. Bret Galbraith	Seminole Electric Cooperative	FRCC	1, 3, 4, 5, 6
4. Ralph Painter Jr.	Tampa Electric Company	FRCC	1, 3, 5, 6
5. Jow Ortiz	Florida Power & Light	FRCC	1, 3, 5, 6
6. Ignacio Ares	Florida Power & Light	FRCC	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
17.	Group	Tom McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

3.	John Babik	FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Erica Esche	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	X		X		X					

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Brian Van Gheem	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ginger Mercier	Prairie Power, Inc.	SERC	3
2.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
3.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
4.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
7.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
8.	John Shaver	Arizona Electric Power Cooperative	WECC	1, 4, 5
9.	John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
10.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	John allen	Iberdrola USA			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Julie King	New York State Electric & Gas	NPCC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Richard Becker	Substation Engineering	WECC	1
2.	Berhanu Tesema	Transmission Planning	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Group	William R. Harris	Foundation for Resilient Societies								X		

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
24.	Individual	Dr. Gabriel Recchia	University of Memphis										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
26.	Individual	Thomas Lyons	Owensboro Municipal Utilities			X							
27.	Individual	Terry Volkmann	Volkmann COnsulting								X		
28.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
29.	Individual	Bill Daugherty	Concerned citizen										
30.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co.			X	X	X					
31.	Individual	John Merrell	Tacoma Power	X									
32.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
33.	Individual	David Jendras	Ameren	X		X		X	X				
34.	Individual	Eric Bakie	Idaho Power	X									
35.	Individual	Terry Harbour	MidAmerican Energy Company	X		X							
36.	Individual	Karin Schweitzer	Texas Reliability Entity										X
37.	Individual	Alshare Hughes	Luminant Generation Company, LLC					X	X	X			
38.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
39.	Individual	John Bee on Behalf of Exelon and its Affiliates	Exelon	X		X		X					
40.	Individual	Richard Vine	California ISO		X								
41.	Individual	PHAN, Si Truc	Hydro-Quebec TransEnergie	X									
42.	Individual	John Pearson/Matt Goldberg	ISO New England		X								
43.	Individual	David Kiguel	David Kiguel								X		
44.	Individual	Bill Fowler	City of Tallahassee			X							
45.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
46.	Individual	Mark Wilson	Independent Electricity System Operator		X								
47.	Individual	Scott Langston	City of Tallahassee	X									
48.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
49.	Individual	Karen Webb	City of Tallahassee					X					
50.	Individual	Bill Temple	Northeast Utilities	X									
51.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
52.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
53.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
54.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
55.	Individual	Catherine Wesley	PJM Interconnection		X								
56.	Individual	Gul Khan	Oncor Electric	X									
57.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
58.	Individual	Wayne Guttormson	SaskPower	X									

1. **TPL-007-1. Do you agree with the changes made to TPL-007-1? If not, please provide a specific recommendation for revisions you could support and justification to support the proposed revisions.**

Summary Consideration: The SDT responded to commenters who raised the following issues:

Underground Transmission. The standard does not specifically address underground transmission lines. The SDT agrees that underground transmission lines are different, should not be modeled as GIC sources, but will conduct GICs. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.

Encouragement of the Use of Regional Collaborative Processes. Commenters suggested that the SDT reinforce the use of regional collaborative processes to accomplish the requirements of the standard. The SDT encourages these processes and has added suggested language to the rationale box to reinforce this position.

Analyses which Span Large Areas. Commenters identified the challenges of performing the required analyses for large systems. The SDT acknowledges this difficulty and offers that flexibility exists in the standard to carry out these analyses in various ways, but also that the presently available power system analysis software allows for varying parameters.

Transformer Thermal Assessments. A number of commenters identified limitations associated with performing the transformer thermal assessments and the potential for heavy dependency on the transformer manufacturers. Transformer manufacturers provided input on the thermal assessment threshold and approach to conducting thermal assessments. In response, the SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.

Specific Identification of Responsible Entities in the Requirements. Commenters suggested specific identification of responsible entities in the requirements in lieu of use of the term "responsible entities". The SDT agrees with the need to be specific in the identification of responsibilities, but recognizes that there are a myriad of organizational structures that subvert the ability to provide specific identification. The SDT continues to believe that the definition of responsibilities required in R1 is the best way to accomplish the objective.

Execution of the Corrective Action Plan. Commenters suggested that the SDT include requirements that address the completion of the Corrective Action Plan. The TPL standards do not address the execution of Corrective Action Plans prepared by the planning entities. Since this standard in part applies to the Generator Owners and Transmission Owners, it was suggested that the standard needs to include requirements related to the execution of the Corrective Action Plan. Other comments suggested that the SDT would be granting new authority to the planning entities if the planning entities were responsible for the execution of the Corrective Action Plan. The concerns relate to the authority of the planning entities to require what could be substantial investments to mitigate the impacts of GMD. Normally, those types of decisions are made by the asset owner, outside of the planning process. The SDT believes that the investment decisions in the case of the GMD Corrective Action Plan will require a collaborative process outside of this standard. To do otherwise would grant additional authority to the planning entities that was not intended and which they do not possess today. The planning entities may use existing processes to address investment decisions, if any.

Harmonics Analysis. Commenters suggested that the tools and capability to perform harmonics analysis are inadequate. The SDT acknowledges that harmonics analysis is a technical specialty and comprehensive harmonics analysis tools and capability are not in wide availability in the industry. However, the SDT believes that some basic harmonics knowledge can be applied in the GMD Vulnerability Assessment process and is necessary to address this reliability risk. FERC Order No. 779 specifies that the vulnerability assessments must account for the effects of "harmonics not present during normal BPS operation." The standard should not take a prescriptive approach on the technical details, but rather refer to the available information. In this case, the GMD Planning Guide and 2012 GMD TF Interim Report provide general considerations for the planner to use (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council Con Edison, Inc	No	The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type

Organization	Yes or No	Question 1 Comment
		transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type 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 and appropriate.On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads:"Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network model."Suggest adding the following paragraph afterwards:"Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model." This comment was submitted during the last comment period.
Response: The SDT agrees that underground pipe-type cables should not be modeled as GIC sources. GIC, induced in the pipe, will circulate through the pipe, cathodic protection and ground return circuit, but it is probably an order of magnitude lower than what		

Organization	Yes or No	Question 1 Comment
be induced in an unshielded transmission circuit. However, the cables will carry GIC induced elsewhere (overhead circuits) and must be included in the dc network (but not as dc sources) as well as the load flow base case. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.		
Colorado Springs Utilities	No	1.) Requirement 4.3 should have to be shared upon request only.We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: The SDT agrees with the comment that encourages regional planning groups to work collaboratively to address the requirements in the standard. The SDT believes that it has provided the flexibility in the standard to support that kind of effort. Regarding the sharing of information among entities, the SDT believes that mandatory sharing of the GMD Vulnerability Assessment is necessary for the RC, adjacent PC, and adjacent TPs to ensure that those entities are aware of information that may be germane to their respective analyses. Other entities can receive the information upon request. In order to better address the comment, the SDT is providing additional clarifying information in the Rationale for Requirement R1. A Rationale box is proposed: ***Rationale for Requirement R1****:* *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		
SERC Planning Standards Subcommittee	No	On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Louisiana as for Minnesota, while conservative, would be absurd. Some sanity in this regard must be maintained among the functional entities to whom this

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>standard would be applicable, particularly for PC’s and their associated TP/TO entities.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that to model a transmission network that spans more than one degree of geomagnetic latitude with the highest alpha value would be very conservative. Commercial software allows users to use different V/km (and thus alpha factors and earth models) in different parts of the network. If an applicable entity can justify (technically) the use of different Epeak values in the model, the standard provides the flexibility of doing so. The specific section in Attachment 1 states:

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

• calculated by using the most conservative (largest) value for α; or
• calculated assuming a non-uniform or piecewise uniform geomagnetic field.</td></tr>
<tr><td>SPP Standards Review Group

Kansas City Power and Light</td><td>No</td><td>5. Background - Replace ‘Misoperation’ with ‘Misoperation(s)’.R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 - set the phrase ‘as determined in Requirement R1’ off with commas.R4 - Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load.Rationale Box for Requirement R4 - Capitalize ‘On-Peak’ and ‘Off-Peak’.Measure M5 - Insert ‘in the Planning Area’ between ‘Owner’ and ‘that’ in the next to last line of M5.Rationale Box for Requirement R5 - Capitalize ‘Part 5.1’ and ‘Part 5.2’. Likewise, capitalize ‘Part 5.1’ under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section.R6/M6 - Capitalize ‘Part 5.1’. Attachment 1 - We thank the drafting team for providing more clarity in the determination of the Î² scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic - When referring to</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Response: The SDT has made several editorial changes. However, some of the suggested changes did not meet the NERC style guide and were not changed. Regarding the question on the number of On Peak and Off Peak studies required, the intent of the SDT was to require that one On Peak and one Off Peak case be studied during the 5 year period. The rationale box has been changed to clearly indicate the SDT's intent: *At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.*		
PPL NERC Registered Affiliates	No	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. 1. The tools available for GOs and TOs to perform the transformer thermal impact assessments of TPL-007-1 requirement 6 are presently inadequate. There are two approaches for such work, as stated on p.4 of NERC's Transformer Thermal Impact Assessment White Paper: use of transformer manufacturer geomagnetically-induced current (GIC) capability curves, or thermal response simulation. We (and probably almost all entities) have no manufacturer GIC data, and the simulation approach requires, "measurements or calculations provided by transformer manufacturers," or, "conservative default values...e.g. those provided in [4]." Reference 4 includes only a few case histories and not widely-applicable transfer functions. Nor does there exist a compendium of, "generic published values," cited on p.9 of the White Paper. Performing thermal response experiments on in-service equipment is out of the question; so enacting TPL-007-1 in its present state would produce a torrent of requests for transformer OEMs to perform studies, this being the only available path forward. We anticipate that

Organization	Yes or No	Question 1 Comment
		each such study would require several days of effort by the OEM and cost several thousand dollars, which would be impractical for addressing every applicable transformer in North America. Generic thermal transfer functions are needed, and the SDT representatives in the 9/3/14 teleconference with the NAGF standards review team agreed, adding that the Transformer Modeling Guide (listed as being "forthcoming" in NERC's Geomagnetic Disturbance Planning Guide of Dec. 2013) will become available prior to the time that GOs and TPs must perform their analyses.We have to base our vote regarding TPL-007-1 on the standard as it presently stands, however. We do not know whether or not the Transformer Modeling Guide will prove suitable, nor is there any guarantee that it will ever be published. We suggest that the standard be resubmitted for voting when all the supporting documentation is available. 2. TPL-007-1 calls for PC/TPs to provide GIC time series data (R5), after which TO/GOs perform thermal assessments and suggest mitigating actions (R6). The PC/TPs then develop Corrective Action Plans (R7), which are not required to take into account the TO/GO-suggested actions and can include demands for, "installation, modification, retirement, or removal of transmission and generation facilities." The SDT representatives on the NAGF teleconference cited above stated that granting PC/TPs such sweeping powers over equipment owned by others is consistent with the precedent in TPL-001-4; but we disagree - TPL-001-4 is not even applicable to GOs and TOs. We have high regard for PC/TPs, and we agree that they should be involved in developing GMD solutions, but proposing to give them unilateral control over decisions potentially costing millions of dollars per unit is inequitable. This point is substantiated by the input from Dr. Marti of Hydro One (author of the reference #4 cited above) that they have never had to replace transformers for GMD mitigation; such actions as operational measures, comprehensive monitoring, real time management and studies have been sufficient.

Organization	Yes or No	Question 1 Comment
Response: 1. In order to simplify and facilitate the completion of the transformer thermal assessments, the SDT is proposing two significant changes to the process: (1) the threshold for requiring the performance of a thermal assessment is being raised from 15 amps per phase to 75 amps per phase; and (2) a simplified thermal assessment method based on available models is provided which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.. The above changes should dramatically reduce the number of transformers for which a more detailed thermal assessment is required and will not require the assistance of the transformer manufacturers to execute. Please see the Transformer Thermal Assessment white paper Thermal Screening Criterion for the technical justification for making these changes. 2. Regarding the comment that the standard will be granting new expanded powers to the Planning Coordinator that do not exist today, the SDT responds that it was not the intention of the SDT to grant any additional authority to the PC that they do not presently have under the TPL standards. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where system performance cannot be met during the Benchmark GMD conditions. However, as with other TPL standards, the standard does not address the execution of the CAP. Normally, investment decisions are made by the asset owner outside of the planning process. The SDT believes that the investment decisions in the case of the GMD Corrective Action Plan will require a collaborative process outside of this standard. To do otherwise would grant additional authority to the planning entities that was not intended and which they do not possess today. The planning entities may use existing processes to address investment decisions, if any.		
IRC SRC	No	1. The ISO/RTO Standards Review Committee (SRC) respectfully submits that the modifications to the measure remove the ability of Planning Coordinators to vet and implement protocols that are broadly applicable to Transmission Planners in its footprint through a consensus process. The requirement to develop individual protocols in coordination with each and every Transmission Planner individually creates unnecessary and unduly burdensome administrative processes that lack a corresponding benefit. The requirement and measure should be modified to allow Planning Coordinators to utilize consensus processes generally and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, th SRC notes that the modeling data

Organization	Yes or No	Question 1 Comment
		itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since that standard deals with load flow, stability, and short circuit data. Accordingly, the SRC recommends that requirements R2 and R3 from MOD-032 be added as requirements in the beginning of the GMD standard and substitute the word “GMD” where it states “steady-state, dynamic, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. In addition to adding the requirements noted above, the below revisions are proposed:R1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall delineate the individual and joint responsibilities of the Planning Coordinator and these entities in the Planning Coordinator’s planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). [Violation Risk Factor: Low] [Time Horizon: Long-term Planning] M1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and copies of procedures or protocols in effect that identifies that an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.Corresponding revisions to VSLs are also recommended. 2. The SRC notes that the use of the term “Responsible Entities” “as determined under Requirement R1” is ambiguous and could be modified to be more clearly stated. The below revisions are proposed:”Entities assigned the responsibility under Requirement R1”Corresponding revisions for associated measures and VSLs are also recommended. 3. The SRC respectfully reiterates its comment 2 above regarding the term “Responsible Entities” “as determined under Requirement R1” and recommends

Organization	Yes or No	Question 1 Comment
		that, for all instances where "Responsible Entity" is utilized in Requirement R3, similar revisions are incorporated. Corresponding revisions for associated measures and VSLs are also recommended. 4. The SRC respectfully reiterates its comment 3 above for all instances where "Responsible Entity" is utilized in Requirement R4. It further notes that Requirement R4 is ambiguous as written. More specifically, the second sentence could more clearly state expectations. The following revisions are proposed:R4. Entities assigned the responsibility under Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, include documentation of study assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] Corresponding revisions for associated measures and VSLs are also recommended. 5. The SRC respectfully reiterates its comment 3 above for all instances where "Responsible Entity" is utilized in Requirement R5. Additionally, for Requirement R5, no timeframe is denoted for provision of the requested data. To ensure that requested or necessary data is provided timely such that it can be incorporated in the thermal assessment required pursuant to Requirement R6. It is recommended that the requirement be revised to include a statement that the data is provided by a mutually agreeable time. Corresponding revisions for associated measures and VSLs are also recommended. 6. The SRC respectfully submits that, as written, Requirement R6 appears to require an individual analysis and associated documentation for each power transformer and does not allow Transmission Owners and Generator Owners to gain efficiencies by producing a global assessment and set of documentation that includes all required equipment. It further does not allow these entities to collaborate and coordinate on the performance of jointly-owned equipment, creating unnecessary administrative burden and reducing the exchange of

Organization	Yes or No	Question 1 Comment
		information that could better inform analyses. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5; 6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and 6.4. 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. Corresponding revisions for associated measures and VSLs are also recommended. 7. As a global comment, the confidentiality of the information exchanged pursuant to the standard should be evaluated and, if necessary, the phrase “subject to confidentiality agreements or requirements” inserted in Requirements R3 through R7. Corresponding revisions for associated measures and VSLs are also recommended.
Response: 1. The SDT agrees with the comment that encourages regional planning groups to work collaboratively to address the requirements in the standard. The SDT believes that it has provided the flexibility in the standard to support that kind of effort. The SDT reviewed MOD-032 and decided not to include portions of the standard as suggested in the comment. The SDT believes that		

Organization	Yes or No	Question 1 Comment
MOD-032 is intended to address data more generally than is considered in the comment. TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements for steady state analysis and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes. Future revisions of MOD-032 should be updated to maintain a single modeling standard 2-5. The SDT agrees with the comment on the use of the term "responsible entities" and will make changes as suggested. 6. The SDT agrees with the first part of the comment and revised the wording in the standard to clarify that documentation covering all applicable BES power transformers could be used to satisfy the requirement. 7. Confidentiality of information is covered under NERC Rules of Procedure, so the SDT did create a requirement to duplicate the provisions. However, rationale boxes have been updated with guidance.		
ACES Standards Collaborators	No	(1) We would like to thank the SDT for already addressing many of our concerns regarding the previous drafts of this standard. However, we still have a concern regarding how the applicable entities are identified in this standard and recommend the SDT designate the Planning Coordinator as the applicable entity for compliance with Requirement R1. R1 lists both the PC and the TP as concurrently responsible for compliance, 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, should be the entity responsible for performing the GMD Vulnerability Assessment. The SDT identifies their justification for this approach is the same as the one taken in other planning standards, and while we appreciate an effort to maintain consistency between standards, this approach has forced many entities to plan and implement formal coordination agreements between PCs and TPs on a regional basis to identify the responsibilities of conducting these assessments. The approach spreads the burden of compliance among many entities rather than directly assigning the responsibilities to just a smaller set, the Planning Coordinators. We believe the SDT should remove each reference to "Responsible entities as determined in Requirement R1" and instead properly assign the PC.(2)

Organization	Yes or No	Question 1 Comment
		We appreciate the SDT providing their justifications for a facility criterion with the applicability of this standard; however, we believe the SDT should remove this criterion and instead utilize the current BES definition that went into effect on July 1, 2014. Like the SDT, we also acknowledge that parts of the proposed standard apply to non-BES facilities and that some models need such information to accurately calculate geomagnetically-induced currents. However, that criterion should be identified within the Guidelines and Technical Basis portion of the standard. Adding the facility criterion upfront in the applicability section of the standard provides confusion to both industry and auditors when 200 kV high-side transformers may apply. The BES definition identifies all Transmission Elements operated at 100 kV or higher and accounts for inclusions and exclusions to that general definition. The SDT should leverage the technical analysis that was performed to achieve industry consensus and FERC approval for the revised BES definition. The current approach only provides additional confusion.
Response: The SDT reconsidered the use of the term "responsible entities" and while it agrees with the concept of specifically identifying the entities who will have the responsibility to perform, the SDT did not feel that it could change the terminology due to the diversity of how the entities are organized in the North American system. The SDT continues to believe that the respective responsibilities need to be sorted out via group discussions facilitated by the Planning Coordinator as envisioned in R1.		
Foundation for Resilient Societies	No	COMMENTS OF THE FOUNDATION FOR RESILIENT SOCIETIES (Comment 1 of 2 submitted 10-10-2014)TO THE STANDARD DRAFTING TEAM NERC PROJECT 2013-03 - STANDARD TPL-007-1TRANSMISSI0N SYSTEM PLANNED PERFORMANCE FOR GEOMAGNETIC DISTURBANCE EVENTSOctober 10, 2014Answer to Question 1: No, we do not agree with these specific revisions to TPL-007-1. Detailed responses are below. 1. Requirement R3 should contain steady state voltage "limits" instead of the subjective term "performance." Measure M3 should contain steady state voltage "limits" instead of the subjective term "performance."

Organization	Yes or No	Question 1 Comment
		2. Table 1, “Steady State Planning Events” has been changed to allow “Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service” as primary means to achieve BES performance requirements during studied GMD conditions. When cost-effective hardware blocking devices can be installed, load loss should not be allowed. Protective devices that keep geomagnetic induced currents (GICs) from entering the bulk transmission system extend service life of other critical equipment, allow equipment to “operate through” solar storms, reduce reactive power costs and support higher capacity utilization. In contrast, load shedding while GSU transformers remain in operation tend to reduce equipment life and continue to allow GICs into the bulk power system, risking grid instabilities. Capacitive GIC blocking devices are, to first order, insensitive to uncertainties in GMD currents and thus protect the grid against a large range of severe GMD environments. 3. Table 1, “Steady State Planning Events” has been changed to allow Interruption of Firm Transmission Service and Load Loss due to “misoperation due to harmonics.” When cost-effective hardware blocking devices can be installed, misoperation due to harmonics should be prevented. 4. On page 12, text has been changed to “For large planning areas that span more than one Î² scaling factor from Table 3, the most conservative (largest) value for Î² should may be used in determining the peak geoelectric field to obtain conservative results.” “May” is not a requirement; the verb “should” needs to be retained in the standard. 5. Under “Application Guidelines,” Requirement R6 now reads: “Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2

Organization	Yes or No	Question 1 Comment
		is also a justifiable threshold criterion that exempts a transformer from Requirement R6." These exemptions from the assessment requirements of this standard, both singly and in combination, defeat a key purpose of FERC Order No. 779, which is to protect the bulk power system from severe geomagnetic disturbances: (1) By failing to require the utilization of now-deployed and future-deployed GIC monitors, of which there were at least 102 in the U.S. in August 2014 (see Resilient Societies' Additional Facts filing, Aug 18, 2014, FERC Docket RM14-01-000), and now at least 104 GIC monitors, NERC fails to mandate use and data sharing from actual GIC readings, and cross-monitor corroboration of regional GIC levels. This systematic failure to use available risk and safety-related data may enable "low-ball modeling" of projected GIC levels both at sites with GIC monitors and at other regional critical facilities within GIC monitoring; (2) The so-called "benchmark model" developed by NERC significantly under-projects GICs and electric fields. The Standard Drafting Team, in violation of ANSI standards and NERC's own standards process manual, has failed to address on their merits, or refute with scientific data and analysis, the empirically-backed assertions of John Kappenman and William Radasky in their White Paper submitted to the Standard Drafting Team of NERC on July 30, 2014. See also the Resilient Societies' "Additional Facts" filing in FERC Docket RM14-01-000, dated Aug. 18, 2014. Using a smaller region of Finland and the Baltics as a modeling foundation, the NERC Benchmark model under-estimates geoelectric fields by factors of 1.5. To 1.9. This systematic under-estimation of geoelectric fields will have the effect of excluding entities that should be subject to the assessment requirements, thereby reducing the analytic foundation for purchase of cost-effective hardware protective equipment thus allowing sizable portions of the grid to be directly debilitated, with cascading effects on other portions of the grid. (3) In the NERC Standard Drafting Team's review of the Kappenman-Radasky White Paper submitted on July 30, 2014, the STD Notes claim: "They [the

Organization	Yes or No	Question 1 Comment
		Standard Drafting Team] did not agree with the calculated e-fields presented in the commenter's white paper for the USGS ground model and found that the commentator's result understated peaks by a factor of 1.5 to 1.9" Meeting Notes, Standard Drafting Team meeting, August 19 [20014] Comment Review, page 2, para 2b, at page 3. This is altogether garbled. The commenters, using empirical data from solar storms in the U.S. and not in Finland, found the benchmark model understated GICs and volts per kilometer by a factor of 1.5 to 1.9. The Standard Drafting Team has submitted the standard to a subsequent ballot without addressing the Kappenman-Radasky White Paper critique on its merits. This is a violation of both ANSI standards and the NERC standards process manual requirements. (4) To exempt mandatory assessments if a transformer manufacturer's design specifications claim transformer withstand tolerances above the benchmark-projected amps per phase is to place grid reliability upon a foundation of quicksand. (A) Manufacturers generally do not test high voltage transformers to destruction, so their certifications of equipment tolerances are scientifically suspect;(B) As the JASON Summer study report of 2011, declassified in December 2011, indicates: a review of the warranties included with most high voltage transformer sales contracts exclude liability for transformer failures due to solar weather, so "transformer ratings" are not guaranteed and are not backed by financial reimbursement for equipment losses or resulting loss of business claims. The JASONs concluded it was more prudent to purchase neutral ground blocking devices than to pay to test extra high voltage transformers and still risk equipment loss in severe solar weather;(C) The claims of transformer manufacturers have been disputed by national experts, so without testing by a neutral third party, such as a DOE national energy laboratory, these claims are suspect, and should not, without validated third party testing, be an allowable exclusion from mandatory assessment by all responsible entities. See, for example, the Storm Analysis Consultants Report Storm R-112, addressing various unsubstantiated claims by ABB for various transformers. Storm-R-112 noted a

Organization	Yes or No	Question 1 Comment
		number of ABB claims that could not be substantiated. Moreover, in transformer ratings provided to American Electric Power, Kappenman asserts that manufacturer reports have failed to address the most vulnerable winding on the transformer, the tertiary winding. John Kappenman informed the Standard Drafting Team that measurable GIC withstand was much lower than what the manufacturer had estimated for one tested transformer. He further explains that tests carried out by manufacturers only have been able to go up to about 30 amps per phase and were set up to actually exclude or inhibit looking at the most vulnerable tertiary winding on tested transformers. Papers submitted to IEEE and CIGRE discuss these tests but ignore the tertiary winding vulnerabilities. Hence these nonrigorous, manufacturer-biased “ratings” should not, without third party validation, exempt an entity from assessment responsibilities under this standard. (5) The submission of comments today, October 10, 2014, by John Kappenman and Curtis Birnbach, further invalidates the NERC Benchmark model as a basis to design vulnerability assessments. Both the alpha factor and the beta factor of the NERC model significantly under-project GICs and geoelectric field of anticipated quasi-DC currents. The so-called “benchmark” standard is not ready for prime time. If the Standard Drafting Team fails to address the systematic biases in its modeling effort, if it fails to utilize U.S. data and not Finland and Baltic region data, if it fails to require modeling based on the full set of 104 GIC monitors and future added GIC monitors, NERC will be in violation of its ANSI obligations and in violation of the standard validation process set forth in NERC’s own Standards Process Manual adopted in June 2013. (6) Resilient Societies reported to the GMD Task Force as far back as January 2012 that vibrational impacts of GICs were the proximate cause of a 12.2 day outage of the Phase A 345 kV three-phase transformer at Seabrook Station, New Hampshire on November 8-10, 1998. Magnetostriction and other vibrations of critical equipment are associated with moderate solar storms. A moderate North-South/South-North reversing solar storm caused ejection of a 4 inch stainless steel bolt into the winding of the Phase A transformer at Seabrook,

Organization	Yes or No	Question 1 Comment
		captured by FLIR imaging as the transformer melted on November 10, 1998. NERC's own compilations on the March 1989 Hydro-Quebec storm records contain dozens of separate reports of vibration, humming, clanging, and other audible transformer noise at locations within the U.S. electric grid at the time that the GSU transformer at Salem Unit 1 melted. More recently, tests at Idaho National Laboratory in 2012, reported by INL and SARA in scientific papers in 2013, confirm that GICs injected into 138 kV transmission lines cause adverse vibrational effects; and that neutral blocking devices eliminate these vibrational effects. It is arbitrary and capricious for the NERC Standard Drafting Team to fail to address vibrational effects of GMD events, and vibrational elimination when neutral ground blocking equipment is installed. Even if the Standard Drafting Team would prefer a standard that discourages any obligation to install neutral ground blocking devices, such an outcome does not comply with ANSI standards. Evidence-based standards are needed. Excluding an entire category of risks (magnetostriction and other vibrations) that are well documented in literature on vibrational risks in electric grids should be unacceptable to NERC, to FERC, and to ANSI. (7) The Standards Drafting Team did not act to address our comments submitted on July 30, 2014, in violation of ANSI requirements that comments be addressed. Areas not addressed include, but are not limited to:(A) No adjustment for e-field scaling factors at the edge of water bodies.(B) No standard requirement for the assessment of mechanical vibration impacts.(C) No requirement for testing of transformers to validate thermal and mechanical vibration withstand when subjected to DC current limits.(8) Our concerns with NERC's speculative "hot spot" conjecture for GIC impacts over wide areas were not addressed. Under separate cover to NERC, we are submitting data and analysis that shows NERC's "hot spot" conjecture is inconsistent with real-world data. In conclusion, we note that the Federal Energy Regulatory Commission in its Order No. 779 [143 FERC Â¶ 61,147, May 16, 2013) ordered "that any benchmark events proposed by NERC have a strong technical basis." Emphasis added,

Organization	Yes or No	Question 1 Comment
		quoting Order No. 779 at page 54.For the above reasons, among others, NERC's draft standard TPL-007-1 does not presently have a "technical basis" for its implementation, let alone a "strong technical basis" as required by FERC's Order.

Response: Thank you for your comments, we appreciate your participation in the standard development process.

1. R3 was changed in response to comments from several stakeholders. Voltage limits remain an acceptable criteria. As written, R3 accepts voltage limits and provides flexibility for development of more sophisticated methods of determining voltage stability.

2. Performance criteria in table 1 meets the directives of FERC Order 779. The SDT also believes that this criteria which permits load loss is consistent with planning criteria for other extreme events. The comment is not supported by the state of the art in hardware mitigation.

3. Performance criteria in table 1 meets the directives of FERC Order 779, as does including harmonic impacts (P.67). The comment is not supported by the state of the art in hardware mitigation.

4. The section referred to in the comment provides two alternatives that are equally acceptable, so the standard is worded appropriately.

5. The Screening Criterion white paper provides the technical explanation for the selection of the GIC threshold. The criterion is conservative which allows for significant variations by type, design, age, and other factors. A design specification for a transformer provides a reasonable technical basis for excluding a transformer from mandatory requirements for thermal assessment. However good engineering practice may indicate to an owner that a detailed assessment is warranted.

The standard addresses the assessment parameters of order 779. Vibration impacts are not included in the standard. Available information is sparse and mostly anecdotal. Available information does not suggest vibration would likely have a wide area impact.

The SDT has previously responded to comments on water bodies, vibration, transformer tests to determine thermal time constants, and the technical development of the benchmark event. As noted herein, "if you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been

Organization	Yes or No	Question 1 Comment
an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]" Response to Supplemental Comment "NERC Request for Comments on TPL-007" (appended) To be accurate, the spatially-averaged geoelectric field amplitude is 8 V/km, not 5.77. The averaging process does not explicitly assume the existence of ionospheric hotspots. The geoelectric field is characterized in regional scales without making any assumptions about the actual field structure. Of course, localized hotspots, if they exist, will be reduced in amplitude in the averaging process as we are interested in regional-scale rather than point wise enhancements in the field. Large-scale spatially coherent enhancements would not be reduced in amplitude in the averaging process. The observation in the comment of "simultaneous GIC peaks" or "simultaneous dB/dt" has no relation with the methodology used to develop the benchmark geoelectric field amplitude (8 V/km). It is not possible, and it can be quite misleading, to analyze Figure 1 in the supplemental comment without a power system model. However, if we neglected the effects of power system topology and network resistance (which we emphasize cannot be done), we notice that Rockport measured 80 A while Kammer measured only 40 A; i.e., half the GIC magnitude of Rockport. Similarly, Figure 3 shows that OTT measured more than twice the peak amplitude dBx/dt than STJ. This is precisely why the standard contemplates wide-area spatial averages to estimate extreme geoelectric fields. It would be incorrect to define a benchmark to be applied continent-wide when we observe significant differences across the system driven by geographic (latitude and ground conductivity) and system characteristics.		
PacifiCorp	No	Please refer to the response for #4.
University of Memphis	No	I would support a version of TPL-007-1 for which the statistical analyses were recomputed to take the considerations I mention in my responses to Question 4 into account, for which the numbers in TPL-007-1 Attachment 1 were adjusted accordingly, and for which the standards were adjusted to be appropriate given the new values.

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Organization	Yes or No	Question 1 Comment
Response: See response in Question 4.		
American Electric Power	No	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.The drafting team continues to state that it is the responsibility of the owner to mitigate. 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 or the drafting team must clearly communicate how they envision the coordination between the PC/TP and the TO/GO occurring.TOs and GOs need to be involved in the development of the Corrective Action Plans that they will required to execute. The standard should require the PC to set up a stakeholder process with TOs and GOs related to these corrective action plans. The stakeholder process would take into account considerations such as scope of corrective action plans, schedules, market impacts, etc.
Response: The intent of R6 is to provide planners with the necessary thermal assessment information to complete a GMD Vulnerability Assessment, which by definition includes equipment impacts. The rationale box has been revised to provide clarity. I It is not the intention of the SDT to grant any additional authority to the PC that they do not presently have under the TPL standards. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where system performance cannot be met during the Benchmark GMD conditions. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. The reason for this is due to the fact that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction and outside the purview of reliability standards.		

Organization	Yes or No	Question 1 Comment
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: There have been a number of historical events, most notably the 1989 Hydro Quebec blackout, that have been attributed to GMD. Based on those historical events, prudency dictates that the potential reliability issues associated with this phenomenon be assessed and mitigated.		
Volkmann Consulting	No	There is no technical justification to add an additional year to the process to an imminent problem.
Response: The SDT received a number of comments suggesting that the implementation plan for the standard is too short. Given that the process will require additional data, models, and assessment tools and practices that are new to the various entities, the SDT believes that that the extended implementation timeframe is reasonable.		
Seminole Electric Cooperative, Inc.	No	(1) Seminole is confused as to whether the CP-3 value has been finalized by USGS or not, as USGS's website does not reflect the CP-3 value represented in the latest ballot. If the ground conductivity value for the Florida Peninsula, CP-3, is not final, i.e., USGS is still developing and researching the value, then the drafting team should delay vote on the Standard or allow for successive balloting on the final CP-3 value when USGS finalizes its value. Seminole does not believe the NERC Standards Process Manual allows for revisions to the CP-3 value after the Standard has been approved without re-opening the balloting.(2) Seminole is aware that a CEAP is not required to be performed, however, Seminole believes a CEAP is justified in this particular circumstance.
Response: 1. The ground model for Florida has been provided. USGS is in the process of updating their website. The standard allows the use of updated models at any time as specified in Attachment 1. 2. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the		

Organization	Yes or No	Question 1 Comment
potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
Concerned citizen	No	The selection of the March 13-14 1989 GMD (Hydro Quebec) and the October 29-31 2003 Halloween events to define the 100 year GMD standards ignores a substantial body of work by researchers such as Bruce Tsurutani (NASA) and Daniel Baker (University of Colorado). NERC has chosen to define the 100 year GMD based solely on GMD events that were measured when CMEs actually hit the Earth in the 1980 to 2013 time frame. This ignores the work done by Tsurutani, Baker, and others that have quantified the magnitude of both pre 1980 events as well as events like the July 2013 event that was directed away from the Earth.The 1989 GMD was not all that strong when viewed on a historical basis, and the 2003 Halloween event, while a X17.2, resulted in a greatly dampened measured effect on the Earth's magnetic field since the magnetic component was pointing northward when it hit the Earth. Had it been pointing southward, the measured effect would have been greatly amplified.This 100 year GMD standard should not be allowed to be finalized without incorporating the findings and recommendations of papers like: Baker, D. N., X. Li, A. Pulkkinen, C. M. Ngwira, M. L. Mays, A. B. Galvin, and K. D. C. Simunac (2013), A major solar eruptive event in July 2012: Defining extreme space weather scenarios, Space Weather, 11, 585-591, doi:10.1002/swe.20097. andTsurutani, B. T., and G. S. Lakhina (2014), An extreme coronal mass ejection and consequences for the magnetosphere and Earth, Geophys. Res. Lett., 41, doi:10.1002/2013GL058825NERC has greatly underestimated the true magnitude of the 100 year threat to the electric grid from solar storms. This must be addressed before these standards are finalized.

Organization	Yes or No	Question 1 Comment
Response: The benchmark GMD event electric field was derived from a statistical analysis of actual magnetometer measurements taken over the course of almost 20 years and extrapolated to the point of 1 in 100 year probability. It was not based on the March 1989 event. However, the March 1989 event was used for the benchmark event time series because it provides a set of high fidelity data that provides conservative results.		
Ameren	No	We still strongly feel that a GMD event of 4-5 times the magnitude of the 1989 Quebec event as the basis for the 1 in 100 year storm is too severe, given the few “high magnitude” events that have occurred over the last 21 years, and therefore we believe that the requirements to provide mitigation for these extreme GMD events are not supported. On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Minnesota as for Louisiana, while conservative, we believe would be absurd. Consideration with respect to unique geographical differences must be maintained among the functional entities to whom this standard would be applicable, particularly for PC’s and their associated TP/TO entities.
Response: The benchmark GMD event is 2 to 2.5 times the March 1989 event, not 4-5 times. That said, the SDT needed to select a technically defensible electric field benchmark that was sufficiently conservative to encompass expected severe events without taking an event that was highly improbable. The 1 in 100 years probability appeared to the SDT to be a reasonable choice for the benchmark. The SDT continues to believe that the Pulkinnen et al statistical analysis provides the best analysis to address the above need. Regarding the issue of geomagnetic scaling, the SDT agrees that to model a transmission network that spans more than one degree of geomagnetic latitude with the highest alpha value would be very conservative. Commercial software allows users to use different V/km (and thus alpha factors and earth models) in different parts of the network.		
Texas Reliability Entity	No	1. Requirement R3: Texas Reliability Entity, Inc. (Texas RE) requests the SDT consider and respond to the concern that GMD criteria in the proposed standard

Organization	Yes or No	Question 1 Comment
		for steady state voltage performance is different than the steady state voltage performance criteria in other TPL standards or the SOL methodology. GMD events will typically not be transient in nature so adopting the steady state approach is preferable as it would simplify the studies if the voltage criteria between GMD events and other planning events were the same. 2. Requirement R7: Texas RE intends to vote negative on this proposed standard solely on the basis that we remain unconvinced that the proposed standard meets the intent of FERC Order 779. Paragraph 79 for the following reasons: (A) Reliance on the definition of Corrective Action Plans (CAP) in the NERC Glossary in lieu of including language in the requirement appears insufficient to address the FERC statement that a Reliability Standard require owners and operators of the BPS to “develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event.” While Texas RE agrees that requiring the development of a CAP in Requirement R7 meets part of the FERC directive, R7 falls short as there is no language in the requirement (and therefore the standard) that addresses completion of the CAP. The CAP definition calls for an associated timetable but does not address completion. Coupled with the language in R7.2, that the CAP be reviewed in subsequent GMD Vulnerability Assessments, it is conceivable that a CAP may never get completed as timetables can be revised and extended as long as the deficiency is addressed in future Vulnerability Assessments. Without a completion requirement, a demonstrable reliability risk to the BES may persist in perpetuity. Texas RE recommends the SDT revise Requirement R7.2 as follows: “Be completed prior to the next GMD Vulnerability Assessments unless granted an extension by the Planning Coordinator.” (B) The language in R7.1 does not appear to adequately address the FERC statement that “Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting

Organization	Yes or No	Question 1 Comment
		against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." While R7.1 lists examples of actions needed to achieve required System performance, it does not expressly restrict a CAP from only including revision of operating procedures or training. In addition, Table 1 language regarding planned system adjustments such as transmission configuration changes and redispatch of generation, or the reliance on manual load shed, seem to contradict the FERC language regarding the limiting plans to considering operational procedures. Texas RE suggests the revising the language of R7.1 as follows: "Corrective actions shall not be limited to considering operational procedures or enhanced training, but may include:" Alternatively, Texas RE suggests the addition of language to the Application Guidelines for Requirement R7 reinforcing FERC's concern that CAPs "must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." 3. Compliance Monitoring Process Section: Evidence RetentionTexas RE remains concerned about the evidence retention period of five years for the entire standard. (A) Texas RE reiterates the recommendation that the CAP should be retained until it is completed. The SDT responded to Texas RE's first such recommendation with the following response: "The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance."With a periodic study period of five years, a CAP may extend significantly beyond the five-year window, especially in cases where equipment replacement or retrofit may be required. A retention period of five years could make it difficult to demonstrate compliance and could

Organization	Yes or No	Question 1 Comment
		potentially place a burden on the entity as they will be asked 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. (B) Texas RE also recommends revising the evidence retention to cover the period of two GMDVAs. The limited evidence retention period has an impact on determination of VSLs, and therefore assessment of penalty. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained.
Response: 1. The statement regarding steady state voltage requirements was included in the standard to provide the flexibility that the steady state voltage requirements may be less conservative than those requirements for the ongoing reliability analyses required by TPL-001. The requirement is not intended to prohibit a planning entity from using criteria that are the same as TPL-001. 2. The standard does require the preparation of a Corrective Action Plan (CAP) for situations where the Benchmark GMD conditions cannot be met. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction. 3. The SDT agrees with the comment regarding evidence retention and has edited the standard to modify the requirements regarding evidence retention.		
Pepco Holdings Inc.	No	See Comments on items 2 and 4
Omaha Public Power District	No	The Omaha Public Power District (OPPD) is concerned with language in "Table 1 - Steady State Planning Events" that requires entities to perform steady state planning assessments based on "Protection System operation or Misoperation due to harmonics during the GMD event". The Planning Application Guide's

Organization	Yes or No	Question 1 Comment
		Sections 4.2 and 4.3 specifically mention the unavailability of tools and difficulty in performing an accurate harmonic assessment but does not provide resolution or recommendation on how to accurately address the concern. The statement from Section 4-3 is referenced below. “The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results.”Additionally, there needs to be a clearer definition of how the steady state planning analysis due to GMD event harmonics is to be performed. Is it the intent of the standard to study the removal of all impacted Transmission Facilities and Reactive Power compensation devices simultaneously, sequentially, or individually as a result of Protection operation or Misoperation due to harmonics? The Planning Application Guide references the “NERC Transformer Modeling Guide” in several places as a reference for more information on how to perform the study. The “NERC Transformer Modeling Guide” is shown in the citations as still forthcoming. OPPD doesn’t believe this standard should be approved prior to the industry seeing the aforementioned transformer modeling guide. Further, OPPD does not believe it is feasible to implement a full harmonic analysis in the implementation timeframe for TPL-007. In a very broad view, the standard requires a specific analysis that the industry doesn’t have the skill set or tools to perform. This is acknowledged by the supporting documents. The reference document cited as a resource to further explain how to perform the studies has not been created yet.
Response: The SDT acknowledges that harmonics analysis is a technical specialty and comprehensive harmonics analysis tools and capability are not in wide availability in the industry. However, the SDT believes that some basic harmonics knowledge can be applied in the GMD Vulnerability Assessment process and is necessary to address this reliability risk. Using the available guidance, the planning entities should be able to make some decisions on specific equipment that may be compromised by harmonic currents and		

Organization	Yes or No	Question 1 Comment
thus may be outaged in the network without conducting a harmonics analysis. FERC Order No. 779 specifies that the vulnerability assessments must account for the effects of "harmonics not present during normal BPS operation." The SDT will recommend to NERC technical committees that additional guidance be developed.		
Manitoba Hydro	No	Note "System steady state voltages shall..." was removed from Table 1, which removes the link back to requirement R3. Note d should be re-established and the language similar to that used in TPL-001-4 should be considered: "System steady state and post-Contingency voltage performance shall be within the criteria established by the Planning Coordinator and the Transmission Planner."
Response: The objective of the GMD Vulnerability Assessment is to prevent, voltage collapse, cascading, and uncontrolled islanding. Voltage performance as it pertains to the prevention of the conditions above applies.		
City of Tallahassee	No	Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: 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 Standard Drafting Team (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.
Response: The proposed standard is responsive to FERC directives for development of standards for the assessment of GMD impacts on BPS equipment and the BPS as a whole. Historical records may not reveal low-latitude impacts in North America. The benchmark is of a 100-year magnitude which may result in low-latitude impacts. Geomagnetic latitude and earth structure are taken into account in the GMD Vulnerability Assessment process.		

Organization	Yes or No	Question 1 Comment
South Carolina Electric & Gas	No	On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such having the same geomagnetic scaling factor for a footprint that covers a wide variety of latitudes and bedrock conditions. The individual the applicable entities should be allowed to use judgment in applying the scaling factors.
Response: The standard provides the flexibility to "perform analysis using a non-uniform or piecewise uniform geomagnetic field." This means using different scaling factors in regions with significantly different alpha factors. Entities are given the flexibility to use technically-justified scaling factors other than the maximum.		
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp.	Yes	
MRO NERC Standards Review Forum MidAmerican Energy Company	Yes	The NSRF agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Response: See Question 2.		
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Associated Electric Cooperative, Inc.	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	
Idaho Power	Yes	
Exelon	Yes	
Hydro-Quebec TransEnergie	Yes	
ISO New England	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
ReliabiltiyFirst	Yes	ReliabilityFirst votes in the Affirmative and believes the TPL-007-1 standard enhances reliability and establishes requirements for Transmission system

Organization	Yes or No	Question 1 Comment
		planned performance during geomagnetic disturbance (GMD) events. ReliabilityFirst offers the following comments for consideration. 1. Requirement R7 - During the last comment period ReliabilityFirst provided a comment on Requirement R7 which suggested that R7 should require the Entity to not only develop a Corrective Action Plan but "Implement" it as well. The SDT responded with "CAP must include a timetable for implementation as defined in the NERC Glossary". Even though the NERC definition of CAP implies that an entity needs to implement the CAP, ReliabilityFirst does not believe it goes far enough from a compliance perspective. ReliabilityFirst also notes that other NERC/FERC approved standards (PRC-004-2.1a R1 - "...shall develop and implement a Corrective Action Plan to avoid future Misoperations..." and PRC-004-3 - R6 "Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5...") require entities to "Implement the CAP" so ReliabilityFirst believes it is appropriate to in include this language. ReliabilityFirst offers the following language for consideration: "Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall:"
<u>Response</u>: The SDT does not support the proposed change to Requirement R7. As with other TPL standards, it is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction.		
Tri-State Generation and Transmission Association, Inc.	Yes	Although Tri-State appreciates the intent of the language change in R3, we believe it's now ambiguous as to what is meant by "performance." What did the SDT have in mind with that change? How does the SDT imagine this to be audited?Tri-State believes there is an error in Attachment 1 of the standard. On page 11 under "Scaling the Geoelectric Field" it reads: "When a ground

Organization	Yes or No	Question 1 Comment
		conductivity model is not available the planning entity should use the largest Beta factor of physiographic regions or a technically justified value." However on page 22 of the GMD Benchmark White Paper under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use a Beta Factor of 1 or other technically justified value." These should be consistent and the Attachment in the standard should read as it does in the Benchmark White Paper. There is language already stating that the largest Beta Factor of 1 should be used in cases where entities have large planning areas that span more than one physiographic region.
Response: The SDT believes Requirement R3 provides the necessary obligation for the planning entity to establish performance criteria without prescribing a specific approach. Voltage limits could satisfy this requirement. A rationale box has been added to clarify the SDT intent. Page 22 of the Benchmark GMD Event description has been corrected to be consistent with Attachment 1.		
PJM Interconnection	Yes	
Oncor Electric	Yes	
California ISO		The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

2. **Implementation. The SDT has revised the proposed Implementation Plan from an overall four-year implementation to five years based on stakeholder comments. Do you agree with the changes made to the Implementation Plan? If not, please provide a specific recommendation and justification.**

Summary Consideration: The SDT thanks all who commented. The SDT is not proposing any changes to the implementation plan. However a significant concern with implementation is being addressed through the revisions to the Transformer Thermal Impact Assessment white paper and the revised screening criterion. Specific responses to other comments follow:

- **Timelines for R4 & R5 may not coincide properly and 12 months for developing Corrective Action Plans is insufficient**. The SDT recognized the iterative nature of the GMD Vulnerability Process as depicted in the Application Guidelines section. A summary of implementation is provided (dates reference approval by regulatory authority):
  - 6 months - R1 (Responsibilities)
  - 18 months - R2 (System models)
  - 24 months - R5 (GIC flow information)
  - 48 months - R6 (Thermal Assessment)
  - 60 months - R3 (Performance criterial), R4 (GMD VA), and R7 (CAP).
- **Regarding the data validation and model assumptions for the GMD Vulnerability Assessment and the transformer thermal impact assessment**, the standard allows the use of technically justified earth models or transformer generic models. Technical justification could take the form of updates from USGS and NRCan, as well as adjustments on the basis of concurrent GIC and geomagnetic field measurements.
- **Timeline for coordination and data verification**. **A commenter stated that the time needed to coordinate with neighbors to finalize their models.** The SDT expected the coordination efforts among interconnecting entities in developing system models within the 24-months implementation timeframe. This GMD impact assessment and coordination process is in line with the existing planning process to address any system deficiency issues, and the existing planning coordination mechanism among stakeholders and best practices are expected to apply to the GMD impact assessment process.
- **Tools availability. A commenter stated that GMD Tools are missing**. The revised transformer thermal assessment whitepaper addresses concerns by providing a readily available assessment approach. Also, GMD tools (Geoelectric Field Calculator and Thermal Assessment Tool) developed by Hydro One were provided to facilitate the GMD Vulnerability Assessment and the transformer thermal impact assessment. Available at: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Planning-Tools.aspx

Organization	Yes or No	Question 2 Comment
Colorado Springs Utilities	No	1.) As many companies are going to be required to buy software and train for the specific modeling being required we recommend that this requirement have a 24 month implementation period. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: Based on the other industry comments and the SDT's experience the implementation period for R2 is maintained at 24-calendar months after the effective date of the standard.		
Florida Municipal Power Agency FRCC GMD Task Force	No	FMPA supports the comments of the FRCC GMD Task Force (copied below).The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of 'priliminary' with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force 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

Organization	Yes or No	Question 2 Comment
		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.
Response: The ground model for Florida has been provided. USGS is in the process of updating their website. The standard allows the use of updated models at any time as specified in Attachment 1.		
Duke Energy	No	Based upon our review of the Implementation Plan, it appears that the proposed timelines for some of the requirements (specifically R4 & R5) may not coincide properly. We request further explanation of the timelines, and their relationships between the various requirements.
Response: Timelines in R4 and R5 support the overall GMD VA process as depicted in the application guideline. Details have been provided in the rationale boxes of the standard to clarify the sequencing.		
Associated Electric Cooperative, Inc.	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,

Organization	Yes or No	Question 2 Comment
		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.
Response: The revised standard and thermal impact assessment white paper address the model availability concern. The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method for transformers which can be used for a conservative assessment of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. The SDT did not support adding a specific milestone for coordination of models with neighboring entities. This could be part of a planner's input to the coordination of responsibilities with the PC that must occur in Requirement R1. Regardless, the team believes that an entity will be able to have models of their planning area within 18 months of the effective date of the standard.		
IRC SRC California ISO	No	Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised.

Organization	Yes or No	Question 2 Comment
Response: Implementation times are coordinated to be consistent with the GMD VA process as depicted in the Application Guidelines section. The implementation plan establishes the required completion date. In order to complete the GMD VA, the planner must have the thermal assessment information from the equipment owners.		
ACES Standards Collaborators	No	We appreciate the SDT's recognition that the previous implementation plan identified for this standard was too short and burdensome for entities. More time and information need to be made available for entities to properly construct the necessary data models and conduct these new studies correctly. Entities have also received limited assistance with their vendors on the provision of the data necessary to conduct these studies. Large and small entities have limited resources, software, and industry knowledge in this area. Moreover, for smaller entities with limited staff and financial resources, this effort will be a significant challenge. We continue to recommend that the implementation period be extended to eight years to allow industry an opportunity to fully engage in this effort.
Response: Based on the majority of stakeholder feedback and the SDTs experience the implementation plan is maintained at 5 years.		
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: See question 1.		
Volkmann COnsulting	No	There is no technical justification to add an additional year to the process to an imminent problem
Response: The SDT consider the comments of stakeholders and their own experience and is maintaining the 5-year implementation plan.		
Concerned citizen	No	Given the studies that I referenced in my response to Question 1, four years may be too long.

Organization	Yes or No	Question 2 Comment
Response: The SDT consider the comments of stakeholders and their own experience and is maintaining the 5-year implementation plan.		
Pepco Holdings Inc.	No	: Screening models are not developed so this requirement puts the cart before the horse and the revised standard just proposes to move the due date out .
Response: The revised standard and thermal impact assessment white paper address the model availability concern. The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a generic thermal model for transformers which can be used for a conservative assessment of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.		
ISO New England	No	We agree with extending the implementation plan to 60 months. However, more time for the development of the Corrective Action Plan under Requirement R7 should be provided within those 60 months. Once a Corrective Action Plan for one transformer is developed, the entity responsible for developing the Corrective Action Plan will have to run the model again to determine whether another Corrective Action Plan for other transformers is needed as a result of the first Corrective Action Plan. This step may have to be repeated several times. Thus, the time that the entities responsible for developing Corrective Action Plans have from the time they receive the results of the thermal impact assessments under Requirement R6 (which under the current timeline is only 12 months) is insufficient. Accordingly, we strongly suggest that the time for implementation of Requirement R6 be changed from 48 months to 42 months. The time for implementation for Requirement R7 would remain at 60 months but responsible entities would have 18 months to develop the Corrective Action Plans.

Organization	Yes or No	Question 2 Comment
Response: Stakeholder feedback has strongly indicated the need for 48 months to complete R6. The SDT recognizes the challenge of transformer modeling and supports this position. Based on SDT experience and response from most stakeholders, Requirement R7 can be met within 60 months of the effective date of the standard.		
Omaha Public Power District	No	Please refer to comments in Question 1.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Dominion	Yes	
FirstEnergy Corp.	Yes	Increase from 4 to 5 years is an improvement
MRO NERC Standards Review Forum MidAmerican Energy Company	Yes	1. The NSRF agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. We suggest the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement: The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.

Organization	Yes or No	Question 2 Comment
Response: Effective dates in the implementation plan are sequenced to align with the Requirements. Requirement R5 is effective 24 months after the standard's effective date. Because Requirement R6 will become effective 48 months after the standards effective date, the applicable TO and GO has 24 months to complete the assessment as specified in part 6.4.		
SERC Planning Standards Subcommittee	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
SPP Standards Review Group	Yes	Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requirements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
Seattle City Light	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Foundation for Resilient Societies	Yes	With a 60 month implementaiton period, it would be highly beneficial to utilize and require data sharing for the 104 or more GIC monitors now operational in the United States. See Foundation's "Additional Facts" filing in FERC Docket RM14-1-000 of Aug 18, 2014. A model using all the GIC monitors operating now or in the future would enable more cost-effective operating procedures and hardware protection decisions.
Response: GIC measurements are a means to validate and/or adjust earth models. The modelling approach proposed by Kappenman et al is only valid for the system configuration at the time of the measurements. Furthermore, the calibration and accuracy of GIC monitors, especially in the case of low magnitude events is an important consideration that has not yet been addressed at this point in time.		

Organization	Yes or No	Question 2 Comment
PacifiCorp	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	
Ameren	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Idaho Power	Yes	
Texas Reliability Entity	Yes	
Luminant Generation Company, LLC	Yes	
Exelon	Yes	
Hydro-Quebec TransEnergie	Yes	
City of Tallahassee	Yes	
Independent Electricity System Operator	Yes	
City of Tallahassee	Yes	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
South Carolina Electric & Gas	Yes	We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Kansas City Power and Light	Yes	Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requiements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
Tri-State Generation and Transmission Association, Inc.	Yes	
PJM Interconnection	Yes	
Oncor Electric	Yes	
California ISO		The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

3. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for TPL-007-1? If you do not agree, please explain why and provide recommended changes**

Summary Consideration: The SDT thanks all commenters for their feedback on the proposed VRFs and VSLs. Specific responses are below:

- **Commenters did not agree that Requirements R4 and R7 met criteria for a VRF of "high".** They stated that failure to meet these requirements would not directly cause or contribute to BES instability, separation, or Cascading. The SDT finds that proposed requirements meet the criteria for "high" because failure to carry out the actions in these requirements could place the BES at an unacceptable risk of instability, separation, or cascading in a 100-year GMD event. In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred.
- **Commenters did not agree with VSL of "Severe" in Requirement R1 and Requirement R3.** The VSLs are consistent with NERC guidelines which specify that a VSL of "Severe" is appropriate when the requirement does not have any elements or quantities which can be used to evaluate degrees of compliance.

In the revised draft TPL-007-1, the Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). This filing responds to FERC Order No. 786 dated October 17, 2013.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	The NSRF suggest the SDT change the VSL row for Requirement R6 to match the words in the standard.Suggestion:"The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months..." The NSRF suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row.Suggestion:

Organization	Yes or No	Question 3 Comment
		"The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Response: The recommended changes have been made.		
SPP Standards Review Group Kansas City Power and Light	No	Generic - When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.R5 - Capitalize 'Parts 5.1 and 5.2' in the High and Severe VSLs for Requirement R5.R6 - Capitalize 'Part 5.1' and 'Parts 6.1 through 6.4' in the VSLs for Requirement R6.R7 - Capitalize 'Parts 7.1 through 7.3' in the Moderate, High and Severe VSL for Requirment R7.
Response: The recommended format for calendar periods is not in accordance with guidelines in use for consistency. Other recommended changes were made.		
Florida Municipal Power Agency	No	FMPA does not agree with the SDT that failure to meet R4 or R7 could DIRECTLY cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures during a 1-in-100 year GMD event, and continues to believe the VRFs for these requirements should be lowered to medium.
Response: The SDT believes that proposed requirements meet the criteria for "high" because failure to carry out the actions in these requirements could place the BES at an unacceptable risk of instability, separation, or cascading in a 100-year GMD event. In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred.		
IRC SRC California ISO	No	1. Requirement R1 is a purely administrative requirement and, while important to ensure that all requirements are fully satisfied, should not be assigned a "Severe" VSL. A Moderate VSL is proposed.

Organization	Yes or No	Question 3 Comment
		2. Requirement R3 is a purely administrative requirement and, while important to ensure that system performance criteria are documented and understood, should not be assigned a “Severe” VSL. A Moderate VSL is proposed. 3. The VSL assigned to Requirement R2 penalizes the responsible entity for not maintaining “System model”, which is already a requirement in MOD-032-1, R1. Assuming “GIC System model” includes “DC Network models” the VSL language assigned to Requirement R2 should be modified as follows: “The responsible entity did not maintain GIC System models of the responsible entity’s planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).”
Response: NERC and FERC VSL guidelines specify that requirements which cannot be assessed incrementally or via degrees must use VSL of "Severe".		
ACES Standards Collaborators	No	We appreciate the SDT’s efforts to identify measureable criteria for many of the VSLs identified in this standard. However, we continue to disagree with the SDT’s assignment of VRFs for this standard. The SDT identifies that they have aligned the VRFs with the criteria established by NERC. However, we want to remind the SDT of the planning horizon identified in this standard and not to confuse the nature of the event with insufficient or unsupported GMD Vulnerability and thermal impact assessments. We disagree with the categorization of Medium VRFs for the applicable requirements because these requirements could not “under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.” While the nature of the event could affect the electrical state or capability of the BES, we believe not maintaining system models or identifying performance criteria for acceptable system steady state voltage limits would have no affect on the electrical state or capability of the BES.

Organization	Yes or No	Question 3 Comment
Response: In applying the NERC VRF criteria to requirements written for the planning timeframe, the abnormal conditions anticipated by the planning are assumed to have occurred. VRF for Requirement R2 is consistent with other planning standards, NERC guidelines, and FERC's recent orders that affirm VRFs for modeling requirements that are needed for planning.		
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Seminole Electric Cooperative, Inc.	No	See Comments for #1 above and previous ballot Comments.
MidAmerican Energy Company	No	MidAmerican suggest the SDT change the VSL row for Requirement R6 to match the words in the standard.Suggestion:”The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months...”MidAmerican suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row.Suggestion:”The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Response: The suggested edits were made.		
Arizona Public Service Company	Yes	
Dominion	Yes	

Organization	Yes or No	Question 3 Comment
Colorado Springs Utilities	Yes	We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
FirstEnergy Corp.	Yes	
SERC Planning Standards Subcommittee	Yes	
Duke Energy	Yes	
Associated Electric Cooperative, Inc.	Yes	
Iberdrola USA	Yes	
Bonneville Power Administration	Yes	
Foundation for Resilient Societies	Yes	
American Electric Power	Yes	
Volkmann COnsulting	Yes	
Wisconsin Electric Power Co.	Yes	
Tacoma Power	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 3 Comment
Ameren	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	
Pepco Holdings Inc.	Yes	
Exelon	Yes	
ISO New England	Yes	
City of Tallahassee	Yes	
Omaha Public Power District	Yes	
City of Tallahassee	Yes	
Manitoba Hydro	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 3 Comment
Oncor Electric	Yes	

4. **Are there any other concerns with the proposed standard or white papers that have not been covered by previous questions and comments? If so, please provide your feedback to the SDT**

Summary Consideration: The SDT thanks all commenters. Several editorial changes were made throughout the standard.

Modeling Requirements. The SDT believes that MOD-032 provides the necessary means for planning entities to obtain modeling data for GMD Vulnerability Assessments (GMD VA). TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes. Future revisions of MOD-032 should be updated to maintain a single modeling standard.

Regional Cost-Benefit analysis. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require less effort and cost for transformer thermal assessments due to enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives.

Benchmark GMD Event. Specific responses to the various comments are below.

Comparison to Cat D or Cat C from TPL standards. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events.

Specific responses are below:

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
Dominion	No	
FirstEnergy Corp.	No	

Organization	Yes or No	Question 4 Comment
Duke Energy	No	
Associated Electric Cooperative, Inc.	No	
ACES Standards Collaborators	No	(1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. Thank you for the opportunity to comment.
Owensboro Municipal Utilities	No	This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Response: The proposed standard addresses potential wide-area impact caused by a rare GMD event. It is responsive to the Standards Authorization Request and FERC directives.		
Tacoma Power	No	
American Transmission Company, LLC	No	
Texas Reliability Entity	No	
Omaha Public Power District	No	
PJM Interconnection	No	
Oncor Electric	No	
Northeast Power Coordinating Council	Yes	1. The requirements and measures should be revised to allow Planning Coordinators to generally utilize consensus processes and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, the modeling data itself will need to come from the applicable

Organization	Yes or No	Question 4 Comment
		Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since those standards deal with load flow, stability, and short circuit data. Recommend that MOD-32 requirements R2 and R3 be added as requirements in the beginning of the GMD standard, but in R2 substitute the word "GMD" for "steady-state, dynamics, and short circuit". These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. The Applicability section would have to be revised to include the additional entities. 2. Facilities 4.2.1 reads: "Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV." Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read "...wye-grounded winding with voltage terminals operated at 200kV or higher". 3. In Requirement R4 sub-Part 4.1.1. "System On-Peak Load" should be re-stated as "System On-Peak Load with the largest VAR consumption". 4. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x Î± x Î² (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of

Organization	Yes or No	Question 4 Comment
		“antenna” effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections.This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.

Response: The SDT believes that MOD-032 provides the necessary means for planning entities to obtain modeling data for GMD Vulnerability Assessments (GMD VA). TPL-007 Requirement R4 specifies that the GMD VA is based on steady-state analysis. MOD-032 establishes modeling data requirements and Attachment 1 item 9 allows the PC or TP to request information necessary for modeling purposes.

2. Terminal voltage describes line-to-line voltage. The rationale box includes the recommended clarification.

3. By use of the defined term, the SDT is providing a clear requirement that is consistent with TPL-001. The suggested change is also correct but more difficult to determine ahead of time. The existing wording of Requirement R4 part 4.2.2 has been maintained.

4. The suggested changes to the application guide are not accurate. For uniform fields it is ok to model the system with dc sources connected to ground. However, the appropriate way to model non-uniform fields is with voltage source across the line. Refer to: Boteler, D.H.; Pirjola, R.J., "Modelling geomagnetically induced currents produced by realistic and uniform electric fields," *Power Delivery, IEEE Transactions on* , vol.13, no.4, pp.1303,1308, Oct 1998

Organization	Yes or No	Question 4 Comment
Con Edison, Inc.	Yes	1. FAC-003 avoids using the phrase “terminal voltage” by using the phrase “operated at 200kV or higher.” Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read “...wye-grounded winding with voltage terminals operated at 200kV or higher”. 2. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x Î± x Î² (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of “antenna” effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections.This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving

Organization	Yes or No	Question 4 Comment
		DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase.Any other figures with similar oversimplifications should also be changed to avoid confusion
Response: 1. Terminal voltage describes line-to-line voltage. The rationale box includes the recommended clarification. 2. The suggested changes to the application guide are not accurate. For uniform fields it is ok to model the system with dc sources connected to ground. However, the appropriate way to model non-uniform fields is with voltage source across the line. Refer to: Boteler, D.H.; Pirjola, R.J., "Modelling geomagnetically induced currents produced by realistic and uniform electric fields," *Power Delivery, IEEE Transactions on* , vol.13, no.4, pp.1303,1308, Oct 1998		
Colorado Springs Utilities	Yes	Thank you for all of your work on this - this is not an easy one! We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. On some of even the most recent calls there still appears to be some lack of understanding as technical questions are asked. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. We recommend a pilot program. 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. If we pilot the process and shorten the implementation period then the final implementation of the solution could be the same with a much better effect. Please ask the question on the pilot even if the standard must move forward as is. Having the regions and NERC work through the process quickly with a few entities would still be very beneficial. Then all the other

Organization	Yes or No	Question 4 Comment
		companies do not have to repeat the same mistakes to get where we really need to be. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Response: Field tests are governed by Section 6 of the Standards Process Manual (SPM). As described, these programs are conducted prior to formal comment periods to inform the standard development effort. SDT members have collectively conducted multiple GMD studies in many regions and applied their expertise to the development of the requirements and implementation plan.		
MRO NERC Standards Review Forum MidAmerican Energy	Yes	1. Page 9, Table 1 -Steady State Planning Events. The NSRF suggest that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, we suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. 2. Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion:4.2. Facilities:4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.4.2.1 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
Response: 1. Capabilities for assessing the impact of harmonics may vary by planning entity, however these impacts must be considered in a GMD Vulnerability Assessment. General considerations are provided in the GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012. One example of a justifiable approach is based on Section 4.2 of the GMD Planning Guide which states: *SVCs may trip if excessive harmonic current and voltage distortion cause intentional protective relay operation, excessive interactions with the SVC control system, or due to protection misoperation (false tripping) due to vulnerabilities of the protection system.* Since older style electro-mechanical relays are more		

Organization	Yes or No	Question 4 Comment
susceptible to tripping on harmonics, a planner could remove some or all SVCs that are protected by electro-mechanical relays and evaluate System performance. 2. The applicability section is correct for describing the necessary Facilities for this standard. Only Requirements related to thermal assessments (R5 and R6) are specifically limited to BES power transformers.		
SERC Planning Standards Subcommittee	Yes	In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. 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.
Response: The Transformer Modeling Guide is being developed by the NERC GMD TF in the GMD TF Phase II project plan approved by the Planning Committee. Currently commercial GIC software packages include default Reactive Power loss models.		
SPP Standards Review Group	Yes	We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics - Capitalize 'Reactive Power' in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics - Replace 'Wide Area' in the 1st line of the 6th bullet under General Characteristics. The lower case 'wide-area' was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term 'Wide Area' refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don't believe the usage here is restricted to an RC's Wide Area view. The lower case'wide-

Organization	Yes or No	Question 4 Comment
		area' is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude - In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the 'GIC system model'. In Requirement R2 of the standard a similar reference is made to the 'GIC System model' as well as 'System models'. In the later 'System' was capitalized. Should it be capitalized in this reference also? Statistical Considerations - In the 6th line of the 2nd paragraph under Statistical Considerations, insert 'the' between 'for' and 'Carrington'. Statistical Considerations - In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase '1 in 100 year' is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as '1-in-100'. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification - In the 3rd line of the 1st paragraph under the Justification section, the phrase '15 Amperes per phase neutral current' appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as '15 Amperes per phase'. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification - In the 2nd paragraph under the Justification section, the term 'hot spot' appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background

Organization	Yes or No	Question 4 Comment
		section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn't. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification - In the 4th line of the Figure 4 paragraph, '10 A/phase' appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Response: The recommended edits have been made.		
Florida Municipal Power Agency	Yes	FMPA supports the comments of the FRCC GMD Task Force (copied below).The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) 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 FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; "The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies." The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources.
Response: Thank you for your comments, your participation in the standard development process is appreciated. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require		

Organization	Yes or No	Question 4 Comment
fewer man hours and less cost for transformer thermal assessments due enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
FRCC GMD Task Force JEA	Yes	The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC GMD Task Force requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; “The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies.” The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources.It has become very apparent that the SDT and NERC staff are unwilling to analyze the cost for implementation of this Standard, therefore, the FRCC GMD Task Force continues to request 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

Organization	Yes or No	Question 4 Comment
		entities. In support of this request the FRCC GMD Task Force 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, which can be provided upon request.
Response: The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require less effort and cost for transformer thermal assessments due enhancements in the transformer thermal assessment method and screening criterion. The SDT has continued to consider potential costs as it developed requirements to meet the FERC directives. TPL-007 responds to FERC directives in a manner that considers costs. The FERC order No. 779 directs development of standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole (P.2). CEAP could be implemented at a later date when more utilities have a capability for assessing GMD impacts and analyzing costs and benefits.		
City of Tallahassee	Yes	It seems that parameters involved with GMD events and associated GIC’s are still being widely studied and disputed. It would be prudent to submit the “Benchmark GMD Event Data” for a peer review of experts based in the area of Space Science/Physics. 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 Standard Drafting Team (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.

Organization	Yes or No	Question 4 Comment
Response: The proposed benchmark has been developed by SDT members with relevant research and engineering experience. Technical justification has been provided as specified in the project SAR and FERC directives. Peer review is not in the project scope per the SAR, however the analysis has been submitted to a technical journal and is undergoing peer review. Low-latitude impacts have not been recorded however the 100-year benchmark GMD event is more severe than recent events and could potentially cause impacts. The proposed standard accounts for geomagnetic latitude and earth conductivity in the assessments. The Florida ground model has been researched by USGS. Like the other models described in the proposed standard and white paper it is based on available geological literature.		
Seattle City Light	Yes	Seattle City Light is concerned with the effectiveness of the proposed approach (considerations of scientific and engineering understanding aside). Seattle is a medium-small vertically integrated utility, and like many such entities, is registered as a Planning Coordinator and Transmission Planner for our system and our system alone. And like many similar entities, we are closely connected with a large regional transmission utility (Bonneville Power Administration in our case). For this type of arrangement a GMD Vulnerability Assessment performed by Seattle (acting alone) on Seattle's own system (considered alone) will be of little or no value. GMD assessments by other, similarly situated entities likewise will have little or no value. Recognizing the large number of such entities in WECC (something like half of the Planning Coordinators in all of NERC) and the Pacific Northwest, Seattle and others presently are coordinating with regional planning bodies in an effort to arrange some sort of common GMD Vulnerability Assessment that could promise results of real value across the local region. Aside from the usual difficulties attendant upon such an exercise in collaboration, the wording of Requirement R1 that assigns responsibility to Planning Coordinators individually introduces administrative compliance concerns that hinder coordination. Seattle asks that the Drafting Team consider alternative language for R1 (and Measure M1) that would more clearly allow, if not encourage, the possibility for local collaboration among Planning Coordinators. If such changes are not possible, a second best solution would be a paragraph in the guidance

Organization	Yes or No	Question 4 Comment
		documentation stating that collaboration among Planning Coordinators is considered to be a means of meeting compliance with R1.
Response: The proposed standard does not restrict such collaboration from occurring. The SDT agrees with the recommendation to include guidance in the rationale box for R1: *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		
Sacramento Municipal Utility District	Yes	We'd like to express our gratitude and acknowledge the SDT efforts in preparing this standard.We wish to encourage the standard drafting team to consider the flexibility for entities to meet the Requirement R1 through including regional planning groups or something equivalent in Requirement R1. This would allow an entity's participation in such planning groups to meet the terms of the requirement while providing a consistent study approach within a regional boundary. We believe this change meets FERC's intent while alleviating entities duplication of studies while providing a consistent approach on the regional basis.R1. Each Planning Coordinator "or regional planning group", in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). Thank you.Joe Tarantino, PE
Response: Response: The proposed standard does not restrict such collaboration from occurring. The SDT agrees with the recommendation to include guidance in the rationale box for R1: *In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).*		

Organization	Yes or No	Question 4 Comment
IRC SRC California ISO	Yes	1. 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. Specifically, Table 1 provides:"Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event"However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess "Misoperation due to harmonics". The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked. 2. The SRC respectfully notes that this standard is unlike other NERC standards. While the SRC understands that the scope and assignment of the drafting team was to develop standards to implement mitigation of GMD events, the industry has little experience in the matter and, as a result, the proposed standard is a composition of requirements for having procedures and documentation of how an entity performs a GIC analysis for GMD, which essentially makes the overall standard administrative in nature. The SRC would submit to the SDT that this is not the best use of resources and, as these comments point out, are quite removed from direct impacts on reliability. At a minimum, none of the requirements within this standard deserve High VSL ratings. In fact, it is highly probable that, if these requirements were already in effect today, they would be clear candidates for retirement under FERC Paragraph 81. While SRC understands that these requirements are the most effective way to address GMD risk at this time, the compliance resources involved to meet these requirements need to be considered on an ongoing basis and future efforts must be made to evolve the standard into more performance and result-based requirements, which would facilitate the retirement of the procedural/administrative requirements that currently comprise this standard.

Organization	Yes or No	Question 4 Comment
Response: 1. The GMD Planning Guide and 2012 GMD TF Interim Report provide general considerations for the planner to use in a GMD Vulnerability Assessment (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT does not believe that the state-of-the-art for harmonics analysis supports the recommended change. 2. The SDT developed the requirements in TPL-007 to meet NERC guidelines for quality. Development of a GMD Vulnerability Assessment and mitigating actions for a 100-year GMD event are results-based requirements.		
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	Vectren proposes the SDT to consider a different approach to the Applicability and/or registered functions identified in R1. Consider modifying the Applicability section of TPL-007-1 to mirror CIP-014's Applicability section; 'Transmission Facilities that are operating ... 200 kV and ... above at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an 'aggregated weighted value' exceeding ### according the to the table (table to be created by SDT or to use the same from CIP-014). To identify the greatest threat to the Bulk Electric System (BES), the SDT could revise Requirement R1's responsible registered functions to only the Planning Coordinator. Vectren believes the PC performing a system-wide assessment would be of greater value to the BES over including entities with less of an overall reliability impact to the BES. Data to perform the assessment is provided to the Planning Coordinator as part of existing MOD, FAC, and PRC standards.
Response: 1. The triggering event addressed by the CIP-014 standard is not the same as the wide-area nature of GMD events. The SDT is not convinced that wide-area impact of a benchmark GMD event can be assessed using this subset of transformers. 2. The standard provides the flexibility for the PC to carry out the studies or any other entity that may be in a better position to do so. It should be emphasized that asset managers (TO and GO, not the PC) are in the best position to make decisions on equipment that do not impact the reliability of the BES		

Organization	Yes or No	Question 4 Comment
Iberdrola USA	Yes	Direction on the scope of reactive devices to be removed in the standard's Table 1 should be provided. This would include number of devices and/or % within a geographic proximity. It is not clear whether all devices or only specified devices should be removed from service.
Consistent harmonics response		
Bonneville Power Administration	Yes	BPA notes that presently commercial study software does not have the functionality to evaluate the impact of GIC on a transformer; it needs to be capable of this in order to appropriately apply the screening criteria for the complexity of analyzing flows through a transmission network via a benchmark storm. The most significant need is for autotransformers as the core is exposed to an "effective current" influence for the actual flux saturation level which is from an additive or subtractive coupling of current flow in the common and series winding. BPA reiterates our question from the previous comment period: 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.
Response: 1. The SDT agrees with comments on the limitations of commercial tools. TPL-007 requirements can be met with existing tools and techniques. 2. The Outages referred to under Category within Table 1 refer to the Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD Event. As written, it does not require contingency analysis, but does not prevent entities from taking a further step and doing such analyses		

Organization	Yes or No	Question 4 Comment
Idaho Power	Yes	Idaho Power System Planning comments that additional clarity needs added to Table 1 regarding the GMD Event with Outages Category.It is unclear if planners have to include contingency conditions during a GMD event in the vulnerability assessment. If intent of the SDT is to require contingency analysis during a GMD Event to assess system performance; the required contingency categories (i.e. A or N-0, B or N-1, C or N-2) should be clearly identified in Table 1.
Response: The Outages referred to under Category within Table 1 refer to the Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD Event. TPL-007 does not require contingency analysis, but does not prevent entities from taking a further step and doing such analyses		
Foundation for Resilient Societies	Yes	The Foundation for Resilient Societies submits these Comment 1 of 2, and separately. A second comment submitted on Oct 10 2014 involves graphics for concurrent GIC spikes at near-simultaneous times hundreds or even thousands of miles apart. These findings refute the unsubstantiated "GIC Hotspot" model used to average down the effective GIC levels. This bias, combines with the alpha modeling bias (See Kappenman-Radasky White Paper submitted on July 30, 2014) and the beta modeling bias (See Kappenman-Birnbach comments 10-10-2014) in combination result in the NERC GMD Benchmark Model under-estimating overall geoelectric fields and risks to critical equipment by as high as one order of magnitude. Unless corrected, cost-effective purchases of protective equipment will be needlessly discouraged, and the grid will remain at needless risk. ANSI standards and NERC's standards process manual require addressing flaws and criticisms on their merit. This has not been done!
Response: The drafting team has reviewed the supplemental comment and provides the following: 1. The benchmark is 8 V/km, not 5.77 V/km as written in the first paragraph of the supplemental comment. 2. The statistical analysis in the benchmark is used to determine the amplitude of extreme 100-year geoelectric fields. Magnetometers recordings from 1989 GMD event provide a conservative time-series to perform the thermal analysis. The		

Organization	Yes or No	Question 4 Comment
observation of “simultaneous GIC peaks” or “simultaneous dB/dt” has no relation with the proposed methodology to estimate the benchmark geolectric field amplitude (8 V/km). 3. The benchmark geolectric field (8 V/km) was developed using wide-area spatial averages, and therefore, by definition, the geoelectric field can, and does, extend over a wide area. Figure 1 is not in conflict with the methodology used to develop the standard. The local enhancement does not mean that in other regions the geoelectric field must be zero. Figure 1 shows the typical characteristics of the geoelectric field and it is not related to local enhancements. 4. It is not possible, and it can be quite misleading, to analyze Figure 1 without a power system model. However, if we neglected the effects of power system topology and network resistance (which we emphasize cannot be done), we notice that Rockport measured 80 Amps while Kammer measured only 40 Amps; i.e., half the GIC magnitude of Rockport. Similarly, Figure 3 shows that OTT measured more than twice the peak amplitude dBx/dt than STJ. This is precisely why the standard contemplates wide-area spatial averages to estimate extreme geoelectric fields. It would be incorrect to define a benchmark to be applied continent-wide when we observe significant differences across the system driven by geographic (latitude and ground conductivity), system characteristics, and near-space electric current systems.		
PacifiCorp	Yes	PacifiCorp is voting no on this ballot to reflect our concerns (a) that insufficient evidence has been presented to show that the potential impact of a geomagnetic disturbance is significant for the majority of the North American electrical grid, and (b) that the effort that will be required to fully comply with this standard as drafted is not commensurate with the risk. However, PacifiCorp would support this effort if the initial implementation was limited to areas with the highest levels of perceived risk such as areas, for example, above 50 degrees of geomagnetic latitude and within 1000 kilometers of the Atlantic or Pacific coasts. Based on this approach, methods and tools used for the assessment can be further developed while addressing those areas most at risk.PacifiCorp’s concerns can be summarized as follows:(1) The SDT had not provided adequate evidence to show that the impacts of Geomagnetic disturbance are significant at lower latitudes. (2) The at-risk areas for impacts on the transmission system due to Geomagnetic disturbance are limited. The SDT should consider applying this standard only to utilities above 60Â° geomagnetic latitude until adequate data and evidence is available to show lower latitude utilities are impacted to the same degree as higher latitude utilities. (3) In cases where an assessment is

Organization	Yes or No	Question 4 Comment
		deemed necessary, the SDT should consider adding a specific provision where the utilities will be allowed to use prior cycle study results unless a stronger solar storm has been detected than the test signal or significant changes have occurred in the transmission system. Such a provision will reduce the burden on utilities and their customers.
Response: The SDT has reviewed your comment. The SDT recognizes that risk varies with latitude and has developed the benchmark and standard to take this into account. The suggestion to limit applicability to utilities above 60 degree north latitude would not meet purpose of the proposed standard as outlined in the SAR. The revised TPL-007 has incorporated enhancements in the thermal assessment methods that will significantly reduce the effort needed to evaluate thermal impacts. The SDT has added language to the rationale box for R6 to indicate that basing a thermal assessment upon review of the prior thermal assessment is acceptable.		
University of Memphis	Yes	In Appendix I of the Benchmark Geomagnetic Disturbance Event Description, I was concerned to see a decision to compute geoelectric field amplitude statistics that are averaged over a wide area. Appendix I of the Benchmark GMD Event Description currently states "The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales... Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below" (p. 9). However, to prepare for GMDs via the benchmark's current method (averaging over a square area of approximately 500 km in width) is similar to anticipating a 7.0 earthquake somewhere along the California coast, but preparing only for the average expected impact. Because the earthquake is only expected in one particular location, the average impact across the entire coast will be miniscule; if all locations prepared only for the average impact, some would be woefully underprepared. In fact, the assumption is far worse than this earthquake analogy implies, because local failures in interconnected power systems can

Organization	Yes or No	Question 4 Comment
		and do produce wide-area effects, as seen during the 1989 Hydro-Quebec blackout and the Northeast blackout of 2003*. Thus, analyses based on localized spatial scale estimates are precisely what is relevant, not wide-area spatial averages. I am also concerned that the extreme value analysis described does not take into account the fact that extreme space weather events follow a power law distribution (Lu & Hamilton, 1991; Riley, 2012). As stated by Riley (2012), "It is worth emphasizing that power laws fall off much less rapidly than the more often encountered Gaussian distribution. Thus, extreme events following a power law tend to occur far more frequently than we might intuitively expect" (see also Newman, 2005). Therefore it is likely that the analysis substantially underestimates the risk of high geoelectric field amplitudes. *Though not related to GMDs, the Northeast blackout of 2003 is nonetheless a good example of a local failure having wide-area effects.Lu, E. T., and R. J. Hamilton (1991), Avalanches and the distribution of solar flares, Astrophys. J., 380, L89-L92.Newman, M. (2005), Power laws, Pareto distributions and Zipf's law, Contemp. Phys., 46, 323-351.Riley, P. (2012), On the probability of occurrence of extreme space weather events, Space Weather, 10, S02012, doi:10.1029/2011SW000734.

Response: 1. The standard addresses wide area effects. In order to calculate GIC flows, power system engineers were improperly applying across a wide area extreme geolelectric fields derived from single localized observations (for example, 20 V/km across distances of hundreds or even thousands of kilometers). Since geoelectric fields are coherently applied across hundreds of kilometers, the estimation of extreme 100-year geoelectric fields should reflect the geoelectric field magnitude across the same relevant scale. The selection of an area of 500 km provides an adequate scale for spatially coherent fields and is justified by its intended application in power systems, and by the patterns exhibited by IMAGE measurements.

Organization	Yes or No	Question 4 Comment
2. The extreme value statistics do not assume a Gaussian distribution. POT is based on a Generalized Pareto Distribution It can represent the tails of the statistical distribution appropriately.		
American Electric Power	Yes	AEP remains concerned about the availability of the generic screening models. While the drafting team continues to publicize that the use of these models is an option for meeting the TO/GO requirements in R6, the drafting team has also stated that the development of the models is outside of their scope. In order to address uncertainty regarding these generic thermal models, AEP suggests that NERC commit to making industry-wide generic thermal models available as soon as possible, but no more than 18 months after NERC BOT approval of TPL-007-1. AEP supports the overall direction of this project, and envisions voting in the affirmative if the concerns provided in our response are sufficiently addressed in future revisions of TPL-007-1.
Response: The SDT is (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Volkmann COnsulting	Yes	The technical justification for spatial average of the 8V/km has not been adequately vetted among peers, the electric utility has not expertise in this average. In addition the SDT has not justified limiting the peak E-field area to only 100km. If it is 500km this is a huge area of the BES to allow a voltage collapse any outage.

Organization	Yes or No	Question 4 Comment
Response: The proposed benchmark has been technically justified and developed by personnel with research and engineering experience. The analysis has been submitted to a technical journal and is in peer review. The E-field extends over a wide area. The local enhancement (beyond the standard geoelectric field amplitude) can be approximately 100-200 km.		
Wisconsin Electric Power Co.	Yes	For requirement 6 transformer assessment, we have a concern that the data required from the manufacturer of the transformer will not be available, especially for older units where the transformer manufacturer is no longer in business. From the 9/10/14 webinar, it is understood that screening models are in development, but there is no guarantee that they will be available to complete the assessment. Since we currently do not have any means at this time to complete this standard requirement, we will have to vote against approval of this standard.
Response: The SDT is addressing this concern with revisions to the Transformer Thermal Assessment white paper which provides a simplified method for conducting transformer thermal assessments. Revisions to the standard and white paper include: (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Ameren	Yes	What is the estimated cost impact to entities for this activity, and what is the estimated marginal improvement in system reliability? We have heard from peers that the data requirements for a large system would take approximately 1 man-year to develop, and the source for this information is from a utility that has performed this activity per the draft standard. We are concerned given this significant investment in time and engineering resources, is there truly a need for a continent-wide standard when only select areas of the continent need to be concerned with GMD evaluation and mitigation?In the GMD Planning Guide document, one reference

Organization	Yes or No	Question 4 Comment
		noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes.We understand from representatives on the IEEE Transformer Committee that there are concerns that the 15 A threshold identified in the GIC standard is too low. We understand that the IEEE will be making a case to raise this threshold because the likelihood of transformer damage is small at that level of DC current (15 A) for the expected transient durations.]
Response: SDT acknowledges cost and time; however, the proposed implementation schedule has taken into account the time needed and was developed with industry input. Revisions have been made to the transformer thermal impact assessment white paper that will enable all entities to perform a transformer thermal assessment and significantly reduce the burden of those assessments. The standard will provide the reliability benefit defined in the project's SAR and FERC directives. The SDT reviewed feedback from manufacturers that are involved with IEEE. With their support the thermal assessment screening criterion has been raised from 15A per phase to 75A per phase. The revised Thermal Impact Assessment white paper provides a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers. Refer to the Transformer Thermal Assessment white paper and Thermal Screening Criterion white paper.		
Luminant Generation Company, LLC	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 that is applicable to the transformers to be evaluated. Without the

Organization	Yes or No	Question 4 Comment
		curve(s), the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to affirmative 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.
Response: 1. Revisions have been made to the transformer thermal impact assessment white paper that will enable all entities to perform a transformer thermal assessment and significantly reduce the burden of those assessments. 2. The transformer thermal assessment screening criterion has been raised from 15A per phase to 75A per phase. Planning entities determine the peak GIC at each transformers and provide this information to owners in Requirement R5 Part 5.1. 3. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where the Benchmark GMD conditions cannot be met as directed by the FERC order. However, as with other TPL standards, the standard does not address the execution of the CAP. It is expected that the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction		
Pepco Holdings Inc.	Yes	The White papers are an attempt to explain the details but are not technically accurate. This is not a simple topic and much interpretation of the data is required. The response to GIC is related to the transformer ampere turns which determines the flux produced by the GIC. Increased flux increases the losses thus increasing

Organization	Yes or No	Question 4 Comment
		temperatures. Without looking at the transformer design there is no way to be sure where the increase in flux or heating will create the hottest spot or where the heating will take place. Different transformers designs by different suppliers will react differently. A standard GIC profile curve with short duration peak and longer durations of GIC would allow a better delination of suspectable transformer designs rather than a hard number of 15 amperes per phase. Measurements of GIC and temperatures should be an allowable mitigation technique so the transformer response can be seen under many conditions and if needed the unit can be switched off line.
Response: The white papers are based on current technical information. The asset owner is provided latitude to select an approach that they are comfortable with. The transformer thermal assessment screening criterion has been raised from 15A per phase to 75A per phase which will reduce the number of transformers that require a detailed thermal assessment. The SDT agrees that GIC monitoring is a viable component of a mitigation plan.		
Exelon	Yes	The Exelon affiliates would like to express concern with the reliance on transformer manufacturers to conduct the transformer thermal assessment identified in requirement 6. Specifically, our concern is that some transformer manufacturers may not be willing or able to perform the transformer thermal assessments or to provide the required data to conduct transformer thermal assessments in house. We understand that generic transformer models will be made available in the near future and that software tools will also be available to industry, which will utilize these generic transformer models that can be used should the transformer manufacturer be unable or unwilling to perform the thermal assessments. We believe that this approach could produce overly conservative results which may cause the implementation of mitigation measures that would otherwise be unnecessary if the transformer manufacturer data were used so that more accurate results would be achieved. At least one manufacturer has expressed concern that the use of generic

Organization	Yes or No	Question 4 Comment
		models is incorrect because it does not take into account specific design parameters that only the manufacturers have access to. We also understand the implementation plan for TPL-007 will allow time for industry and the transformer manufacturers to work out the methodology and process associated with conducted transformer thermal assessments. Exelon would urge the transformer manufacturers and the NERC GMD Task Force come to a consensus and provide the necessary support and engagement with industry as well as groups supported by industry in developing transformer models and conducting transformer thermal assessments. We would ask that the Standard Drafting Team review the comments submitted by the transformer manufacturers and address them as appropriate.
Response: the SDT is addressing thermal assessment concerns in this revision by (1) raising the threshold for requiring the thermal assessment to be performed from 15 amps per phase to 75 amps per phase, and (2) providing a simplified thermal assessment method based on available models which can be used for a significant number of transformers. The result of the above steps provide an available method for performing transformer thermal assessments, should dramatically reduce the number of transformers requiring more detailed analysis and reduce the necessity of engaging the limited resources of the transformer manufacturers.		
Hydro-Quebec TransEnergie	Yes	Hydro-QuÃ©bec has the following concerns with the proposed standard: 1. The GMD Benchmark Event is too severe to be considered as normal event and should be used as a Extreme situation - the drafting team chose to maintain the 8v/Km value and considers that the 1/100 year should be equivalent to Category C and not Category D of current TPL standards. Hydro-QuÃ©bec concurs with Manitoba Hydro's objection on this point. TPL-007 should follow a format with normal and extreme events, with different compliance requirements. A smaller scale GMD Benchmark Event should be considered as normal event. This is not a minority position, since both Manitoba and QuÃ©bec's electric systems cover a non-negligible portion of Canada.

Organization	Yes or No	Question 4 Comment
		2. The GMD Benchmark Event is too preliminary to be applied on Hydro-QuÃ©bec's system and enforce compliance :ï‚§ The study used statistical value of B and convert this into E. The conversion uses conservative hypothesis which provide approximation that do not reflect HQ's reality. The study consider, for an area of 200 km, a constant value of E which does not reflect a realistic situation for Hydro-QuÃ©bec with a 1,000 km long system. The GMD Event should better take into consideration that the magnetic field and electric field are not constant (e.g. E=f(t)) nor uniform (e.g. E=f(x,y)) when studied on a large distance. It depends on time and location.ï‚§ The direct readings of E should be taken into consideration before retaining the GMD Benchmark Event. Some real measured E values exist and should be used to identify the GMC Event.ï‚§ The 5 to 8 V/Km is too high for the Hydro-QuÃ©bec System. The highest global value observed is less than 3 V/Km. The frequency of the maximum local peak value have been observed for less than two minutes over a 167 month period. That could imply enormous investments on the system to comply to this theoretical GMD Event. 3. Even though the drafting team refers to different guides, it appears that the GMD Vulnerability Assessment is not clear enough. Concurring also with Manitoba comment no 4, the drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The harmonic analysis is missing in the standard. 4. At the 1989 event and after, Hydro-Quebec has not experienced any transformer damage due to GIC and have put strong efforts to test and study GIC effect on Transformer. The 15 A criterion is too simplistic and does not take into account the real operating condition and type of transformer. The evaluation proposed in R6 causes a burden that is not relevant for utilities with high power transformers. 5. TPL-007-1 should be consistent with the philosophy applied in Standard PRC-006. In the latter standard, the TP must conduct an assessment when an islanding frequency deviation event occurs that did or should have initiated the UFLS operation. Similarly, if GMD actually causes an event on the system, then the TP or

Organization	Yes or No	Question 4 Comment
		PC should simulate the event to ensure model adequacy (as per R2) and Assessment Review (as per R4) . 6. From a compliance perspective, there is no mention of what the Responsible entity as determined in R1 is supposed to do with the info provided by the TOs and GOs in R6.4. If the thermal impact assessments are supposed to be integrated in the GMD Vulnerability Assessment, it should be specified in R4. 7. The time sequence and delays are unclear regarding requirements R4, R5 and R6. Many interpretations are possible; the following is one example: a- GMD Vulnerability Assessment 1 (R4) b- GIC flow info (R5) c- Thermal impact assessment and report 24 months later d- Integration in GMD Vulnerability Assessment 2.Since assessments are performed about every 5 years, GMD Vulnerability Assessment 2 will only occur 3 years after reception of the thermal impact assessment?The DT should clarify the time sequence and delays between requirements R4, R5 and R6.

Response:

1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events..

2. The standard allows for non-uniform field based on different ground conductivity and geomagnetic latitude. Analysis of IMAGE data set suggest that geolectric field can be coherent for 500 km. There are too few direct E-field readings to extrapolate a 100-year event. 167 months sample does not represent a return period of 100-year.

3. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For harmonic analysis, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.

Organization	Yes or No	Question 4 Comment
4. The 100-year benchmark is more severe than the 1989 storm. Not having failures in 1989 does not mean that no failures are possible with the benchmark. The 15 A criterion is meant to be simplistic, since it is designed as a screening threshold. The thermal assessment screening criterion has been raised from 15A to 75A. 5. The entity responsible for performing a GMD VA must consider the information provided in Requirement R6. A GMD VA is defined as: *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.* The following has been added to the rationale box for R6: *Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.* 6. The SDT agrees that a post-event analysis is a good practice. Such a requirement is not in the scope of the SAR for this project. 7. Timelines in the implementation plan and within the requirements support completion of a GMD VA every 60 months. The rationale boxes for Requirement R5 and R6 to clarify requirements for repeating assessments. *Rationale addition for R5: At a minimum, GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented susceptibility of localized equipment damage due to GMD.* *Rationale addition for R6: The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.*		
ISO New England	Yes	Section 4.2 in the Applicability section of the standard should be revised to state as follows: "Transformers with a high side, wye-grounded winding with terminal voltage greater than 200 kV." As the SDT explained in its answer to comments received on this section during the previous comment period, the standard applies only to transformers, so the words "[f]acilities that" at the beginning of the sentence are unnecessary and can lead to confusion.TPL-007 Requirement R2 should require rotation of the field to determine the worst field orientation. Without this explicit requirement, a Responsible Entity could miss important GMD impacts and, as a result, the standard may not achieve its stated purpose of "establish[ing] requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon." If

Organization	Yes or No	Question 4 Comment
		the Standard Drafting Team does not include this in Requirement R2, then at the least the Standard Drafting Team should include it in the Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System.
Response: TPL-007 does not apply to transformers only. The applicability section 4.2.1 reflects the necessity to include other Elements in the 200 kV network. Field rotation is described in the GMD TF Planning Guide.		
David Kiguel	Yes	R4 provides for completion of Vulnerability Assessments once every 60 calendar months. As written, it could result in assessments performed as far appart as 120 months of each other if one is completed at the beginning of a 60-month period and the subsequent assessment is completed at the end of the following 60-month period. I suggest writing: once every 60 calendar months with no more than 90 months between the completion of two consecutive assessments. Considerable investment expenses could be necessary to comply with the proposed standard. As such, the standard should not proceed without a solid cost/benefit analysis to justify its adoption, especially considering the low frequency of occurrence of events (the frequency of occurrence of the proposed benchmark GMD event is estimated to be approximately 1 in 100 years). Given the low probability, moderate loss of non-consequential load could be acceptable.
Response: The standard specifies the GMD VAs must be conducted every 60 calendar months with no allowance to exceed that time interval. The SDT has been cost conscious in developing the standard; however a specific cost benefit analysis was not in the project scope as defined in the SAR. The SDT has applied their experience with GMD studies in multiple regions to developing the proposed standard. The revised draft will require fewer man hours and less cost for transformer thermal assessments due enhancements in the thermal assessment method. The standard permits loss of non-consequential load during a benchmark GMD event.		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Yes	The IESO respectfully submits that the SDT has not provided guidance on achieving an acceptable level of confidence that mitigating actions are needed. To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed from service, we suggest that the SDT add a requirement that says “the TO and GO shall seek the PC’s and TP’s concurrence or approval of thermal analysis technique selection”. The IESO also concurs with Manitoba Hydro and Hydro -Quebec comment that the SDT has not provided guidance on what are acceptable assumptions to make when determining which facilities should be removed as a result of a GMD event. The IESO respectfully reiterates our suggestion to amend the planning process to achieve an acceptable level of confidence as follows: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.

Response: The SDT does not agree with the additional language requiring TO/GO to get PC/TP concurrence on thermal assessment techniques. The SDT believes performing a thermal assessment meets responsibilities for the Transmission Owner and Generation Owner under the NERC functional model. With the limited options for thermal assessment, there is little for the TO or GO to get PC/TP concurrence on in terms of technique selection. The SDT's intent is for the TO and GO to provide results of the thermal impact assessment to the planning entity so that identified issues can be included in the GMD VA and, if necessary, the CAP. Like other planning standards, the planner has latitude for determining how to meet performance criteria.

The SDT believes the proposed standard and application guidelines provide sufficient detail to understand the requirements. Like other planning standards, it is not possible or beneficial for the standard and application guidelines to include all of the technical

Organization	Yes or No	Question 4 Comment
details necessary to cover every implementation of the standard for every entity. The standard specifies the assessment parameters and System performance requirements without being technically prescriptive. The SDT believes technical guidance such as may be found in the GMD Task Force guides and SDT white papers will support performance of the requirements by all applicable entities. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For determining equipment to be removed for the planning event in Table 1 due to harmonics, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed.		
Manitoba Hydro	Yes	Manitoba Hydro has five main concerns with the proposed standard: 1. GMD Benchmark Event is too severe - We have made comments previously that we disagree with making a 1/100 year event equivalent to a "Category C" event (as defined in the current TPL standards) in terms of performance requirements. Comments have been made by the drafting team that this is a minority position. Manitoba Hydro's objections are:a) A 1/100 year event "Category D" event is not mandated in Order 779. The FERC Order 779 states "... of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System."b) Manitoba Hydro does not want this to be precedent setting for opening up a review of the extreme events in the current TPL standards and raising the bar for these disturbances in the future. The Transmission Owner should be in the best position to judge their level of risk exposure to extreme events in terms of benefits vs. costs. 2. Thermal Assessments not necessary - We have made recommendations to remove the transformer thermal assessments from TPL-007; specifically remove requirements, R5 and R6. The reason is based on: a) these requirements being burdonesome on utilities in northern latitudes,

Organization	Yes or No	Question 4 Comment
		b) these requirements are based on science that is still evolving,The drafting team is still in the process of finalizing the thermal impact assessment whitepaper. This supporting document should be finalized prior to recommending mandatory standards. c) these requirements having limited reliability benefits,Currently, requirement R6.3 only requires the development of suggested actions. There is no requirement to implement the suggested actions. If no actions are mandated then why is the analysis required? Rather than using a 15 A per phase metric, perhaps R4.4 and R4.5 from TPL-001-4 could be used for guidance where the Planning Coordinator identifies the transformers that are lost or damaged are expected to produce more severe System impacts (eg Cascading) as well as an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence. Such an approach would limit the number of transformers requiring assessment to a manageable number. d) these requirements are not mandated in Order 779.Order 779 does not clearly mention that transformer thermal assessments are required. However, one of the FERC Order 779 requirements implies that a thermal assessment should be done: “If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event.” Damage to critical or vulnerable BPS equipment implies damage due to thermal stress. FERC 779 requires testing for instability, uncontrolled separation or cascading as a result of damage to a transformer or transformers. The TPL-007 standard as drafted does not require an assessment of the impacts of potential loss of a several transformers due to excessive hot spot temperature. Presumably, the hot spot temperature would not coincide to the 8 V/km peak of the benchmark GMD event. The drafting team should specify at what

Organization	Yes or No	Question 4 Comment
		level of GMD (eg 1 V/km) it might be expected that transformers would trip due to hot spot temperature. 3. The TPL-007 standard does not address all of FERC Order 779 - as drafted TPL-007 does not include an assessment of the impacts of equipment lost due to damange that result in instability, uncontrolled separation or cascading failures on the BPS. FERC Order 779 states, "If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event." Instead it appears that the TPL-007 approach may (R6.3 is not worded clearly as to whether or not mitigation is required) require that all elements impacted by thermal heating get mitigated independ of whether or not their loss results in instability, uncontrolled separation or cascading failures on the BPS. Requiring mitigation on elements for which their loss does not result in instability, uncontrolled separation or cascading failures may result in unnecessary costs with no reliability benefits 4. Harmonic Analysis is missing -The drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The approach proposed in the current standard probably wouldn't have prevented the 1989 Hydro Quebec event. The 1989 event was a lesser event (compared to the 1-in-100 year benchmark event) in which system MVAR losses as a result of GIC were relatively insignificant and transformer thermal heat impacts were negligible. The 1989 black out occurred due to protection mis-operations tripping of SVCs due to harmonics, which then triggered the voltage collapse. Unfortunately harmonic analysis tools, other than full electromagnetic transient simulation of the entire network, have not been developed to date. A suggestion is to at minimum require an assessment to identify a list of equipment which when lost due to GIC would result in instability, uncontrolled separation or cascading failures on the BPS. For example this would require the tripping of all reactive power devices (shunt capacitors) connected to a common bus. Equipment

Organization	Yes or No	Question 4 Comment
		(such as SVCs and shunt capacitors) that have been checked to ensure protection neutral unbalance protection is unlikely to misoperate or that are immune to tripping due to harmonic distortion would be exempt (equipment may still trip due to phase current overload during periods of extreme harmonics. However, this is expected to be a local single bus or local area phenomena as opposed to region wide issue like in the Quebec 1989 event). 5. GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC's of 24.5 Amps and 20.2 Amps. Analysis of the EPRI SUNBURST GIC data also indicates that the ALL peak GIC values between 10 Amps to 24 Amps were measured in NERC's supposed geoelectric field cut-off zone (between 40 to 60 degrees geomagnetic latitude).
Response: 1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events.. 2. Requirements for thermal assessment are within the project scope per the SAR. Revisions have been made to the thermal impact assessment white paper that will enable all entities to perform a thermal assessment and significantly reduce the burden of those assessments. The thermal assessment screening criterion has been raised from 15A per phase to 75A per phase. 3. The proposed standard addresses this FERC directive. The planning entity is responsible for assessing System performance per Table 1 in developing the GMD VA. The planner is provided the thermal assessment results from the equipment owner in R6. Thermal assessment cannot be done exclusively on assets with wide area impact due to the wide-area nature of GMD. For example, a certain group of individual assets may not, individually, have a wide area impact. However, some combination of these assets may		

Organization	Yes or No	Question 4 Comment
have a wide area impact. The SDT believes it is necessary for the planner to consider risk for all applicable BES power transformers to ensure that multiple thermal issues do not cause the system to fail to meet performance criteria. 4. Like other results-based standards, TPL-007 does not prescribe how to perform technical details. For harmonic analysis, the following references discuss the impact of harmonics: (see GMD Planning Guide and Section 6 of NERC "*Effects of Geomagnetic Disturbances on the Bulk Power System*", Interim Report, February 2012). The SDT will recommend to NERC technical committees that additional guidance be developed and industry practices such as the one recommended be reviewed. 5. GIC measurements are not a reliable/valid indicator of the average geomagnetic field drop off with latitude. The peak GIC measured in any given transformer depends on the orientation of the geoelectric field and the configuration/orientation of the circuits feeding the transformer. Peak geomagnetic field measurements, on the other hand, are system and orientation independent. Analysis of GIC measurement data, without the configuration of the system, is inadequate and quite possibly misleading. For every meaningful GMD event for which there are Sunburst measurements, there are matching geomagnetic field measurements and these measurements are the basis of the average geomagnetic field drop-off scaling factor.		
SaskPower	Yes	1. GMD Benchmark Event appears to be an extreme event - Making a 1/100 year event equivalent to a "Category C" event in terms of BES performance does not seem supported. 2. Thermal Assessments do not seem to be supported. In general, transformer thermal assessments should be limited to transformers that have a confirmed wide area impact. a) the science is still evolving,b) reliability benefits seem limited,&c) not mandated in Order 779.
Response: 1. Due to its potential wide-area impact from GMD, this standard is not like other TPL standards. In order to meet the directives in FERC Order No. 779 (P. 79), it is not possible to associate GMD Vulnerability Assessment with Category C or Category D events.. 2. Requirements for thermal assessment are within the project scope per the SAR. Revisions have been made to the thermal impact assessment white paper that will enable all entities to perform a thermal assessment and significantly reduce the burden of those assessments. The thermal assessment screening criterion has been raised from 15A per phase to 75A per phase.		

Organization	Yes or No	Question 4 Comment
Northeast Utilities	Yes	It appears that the way Requirement 7.3 of the proposed standard is written presents the potential for competition conflicts under FERC Order 1000. Can the SDT provide feedback to the industry as to what, if any, impact evaluation was done on this requirement as it may impact FERC Order 1000. Compliance with Order 1000
Response: The SDT used a planning approach that is consistent with other planning standards which do not create competition conflicts. As with other TPL standards, the execution of the CAP will be governed by other processes outside of the standards processes, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, for example. A reason for this is that investment decisions and associated cost recovery mechanisms are addressed by regulatory processes that vary from jurisdiction to jurisdiction.		
South Carolina Electric & Gas	Yes	In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. This document has not yet been distributed and, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes, it would be useful to have the opportunity to review it.
Response: The Transformer Modeling Guide is being developed by the NERC GMD TF in the GMD TF Phase II project plan approved by the Planning Committee. Currently commercial GIC software packages include default Reactive Power loss models.		
Kansas City Power and Light	Yes	We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.Benchmark Geomagnetic Disturbance Event DescriptionGeneral Characteristics - Capitalize 'Reactive Power' in the 2nd line of the 3rd bullet under General Characteristics.General Characteristics - Replace 'Wide Area' in the 1st line of the 6th bullet under General Characteristics. The lower case 'wide-area' was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term 'Wide Area' refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC

Organization	Yes or No	Question 4 Comment
		his wide-area overview. We don't believe the usage here is restricted to an RC's Wide Area view. The lower case'wide-area' is used in the paragraph immediately under Figure I-1 under Statistical Considerations.Reference Geoelectric Field Amplitude - In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the 'GIC system model'. In Requirement R2 of the standard a similar reference is made to the 'GIC System model' as well as 'System models'. In the later 'System' was capitalized. Should it be capitalized in this reference also?Statistical Considerations - In the 6th line of the 2nd paragraph under Statistical Considerations, insert 'the' between 'for' and 'Carrington'.Statistical Considerations - In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase '1 in 100 year' is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as '1-in-100'. Be consistent with the usage of this phrase.Screening Criterion for Transformer Thermal Impact AssessmentJustification - In the 3rd line of the 1st paragraph under the Justification section, the phrase '15 Amperes per phase neutral current' appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as '15 Amperes per phase'. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation.Justification - In the 2nd paragraph under the Justification section, the term 'hot spot' appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn't. Whichever, usage is correct (We

Organization	Yes or No	Question 4 Comment
		believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation.Justification - In the 4th line of the Figure 4 paragraph, ‘10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Response: Edits have been made based on this feedback.		
Tri-State Generation and Transmission Association, Inc.	Yes	On page 11 of the "Transformer Thermal Impact Assessment" White Paper it states "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." We are interested to know what is meant by "measured"? Does this have to be done in the lab or can this be done through monitoring of existing transformers?
Response: Measured values could come from the lab or the field. Measured values require installed instrumentation. Of note, the standard provides latitude to use models based on calculated values.		
John Kappenman & Curtis Birnbach		Comments submitted by separate file (appended)
Response: 1. The statistics for the 100-year benchmark GMD event were derived using IMAGE magnetometer data from Northern Europe. Since the near-space electric currents dominate the observed horizontal magnetic field variations on the ground, the same overhead currents will generate similar horizontal ground magnetic field variations at different geographical regions. Consequently, it is appropriate to apply the observed magnetic field observations in Northern Europe to derive geoelectric fields in North America, contemplating the specific geological conditions. 2. The developed spatially averaged statistics required 10-s data from a spatially dense magnetometer array. Such data is not available prior to 1993. The data set, however, includes major storms such as October 2003. The geomagnetic latitude scaling is based on global magnetic data that includes, for example, March 1989 and October 2003 extreme storms.		

Organization	Yes or No	Question 4 Comment
3. The published geomagnetic latitude scaling data set includes March 1989. In addition, analysis of limited data from July 1982 indicates that the boundary location for this storm is consistent with the proposed alpha scaling factor in the NERC benchmark. 4. The commenter's approach for using GIC data to calculate geoelectric fields is valid when an accurate power system model, ground conductivity model, specific power system configuration at the time of measurement, and high data rate magnetometer data is available. Calculations are not accurate without all elements. With limited data it is not feasible to develop a technically-justified benchmark using the commenter's approach.		
Mr. Raj Ahuja, Waukesha Mr. Mohamed Diaby, Efacec Dr. Ramsis Girgis, ABB Mr. Sanjay Patel, Smit Mr. Johannes Raith, Siemens		Comments submitted by separate file (appended)
Response to comment on R5 screening criterion: 1. The SDT agrees that 15 A is overly conservative. The screening criterion has been increased to 75 A per phase based on simulations of benchmark GMD event conditions on transformer thermal models. Details are provided in the screening criterion white paper. The new screening criterion is still conservative to account for any condition and all types of transformers to determine if detailed analysis should be performed. 2. At his point in time there is very limited measurement-base information on 3-limb core-type transformers to support a specific threshold. Response to comment on R6 thermal impact assessment. 1. GIC(t) depends on storm orientation and system configuration at the time of the event. During any one event, GIC(t) will be different in every transformer of the system. While it would be desirable to have one-signature-fits-all waveshape, it is unclear what set of parameters would be appropriate for all transformers in one event, let alone all transformers in all events. As stated in the thermal impact assessment white paper, the SDT selected the March 1989 event among others because the waveshape of B(t) had a frequency content and characteristics that resulted in higher temperatures. Newly added simulation results (see Figure 9-3 of the thermal assessment white paper) emphasize this observation. The conservative nature of the benchmark waveshape is not specific to		

Organization	Yes or No	Question 4 Comment
any one transformer model or thermal transfer function. The standard specifies that the thermal impact assessment shall be based on GIC flow information for the benchmark GMD event (Requirement R6 part 6.2). This requirement meets FERC directives which delineate assessment parameters for determining vulnerability of BPS equipment and the BPS as a whole to the benchmark GMD event (Order No. 779 P. 67). The SDT agrees that a general-purpose simplified test waveshape would be desirable. However more research is required to compare the results of such a test waveshape against measurement-based waveshapes, and to determine what parameters would account for the variety of measured waveshapes known to date.		
EIS Council		Comments submitted by separate file (appended)
Response: 1. The proposed benchmark continues the work of the GMD TF and is responsive to FERC Order No. 779 which directs protection against instability, uncontrolled separation, or cascading failures as a result of a benchmark GMD event. For this application, GIC flows should not be based upon statistics derived from single localized observations as advocated by the commenter. 2. There is no direct evidence about the geoelectric field amplitudes for the 1921 Railroad Storm. Absence of recorded data precludes rigorous comparison. The frequency content of the March 1989 storm has been shown in the white paper to a conservative selection from available data. 3. The analogy to bridge design is not valid for considering wide area effects directed by Order No. 779. 4. The March 1989 event provides one parameter of the benchmark GMD event. The commenter is incorrect in referring to this event as the benchmark. The March 1989 event provides a conservative waveshape for transformer thermal impact assessment. The magnitude of the benchmark (used in power flow analysis and transformer thermal impact assessment) is a 100-year event determined through statistical analysis of magnetometer data. 5. Plots in the submitted comments are difficult to understand without scales and legends.		

NERC

END OF REPORT

Response to NERC Request for Comments on TPL-007-1

Comments Submitted by the Foundation for Resilient Societies
October 10, 2014

The Benchmark Geomagnetic Disturbance (GMD) Event whitepaper authored by the NERC Standard Drafting Team proposes a conjecture that geoelectric field "hotspots" take place within areas of 100-200 kilometers across but that these hotspots would not have widespread impact on the interconnected transmission system. Accordingly, the Standard Drafting Team averaged geoelectric field intensities downward to obtain a "spatially averaged geoelectric field amplitude" of 5.77 V/km for a 1-in-100 year solar storm. This spatial averaged amplitude was then used for the basis of the "Benchmark GMD Event."[1]

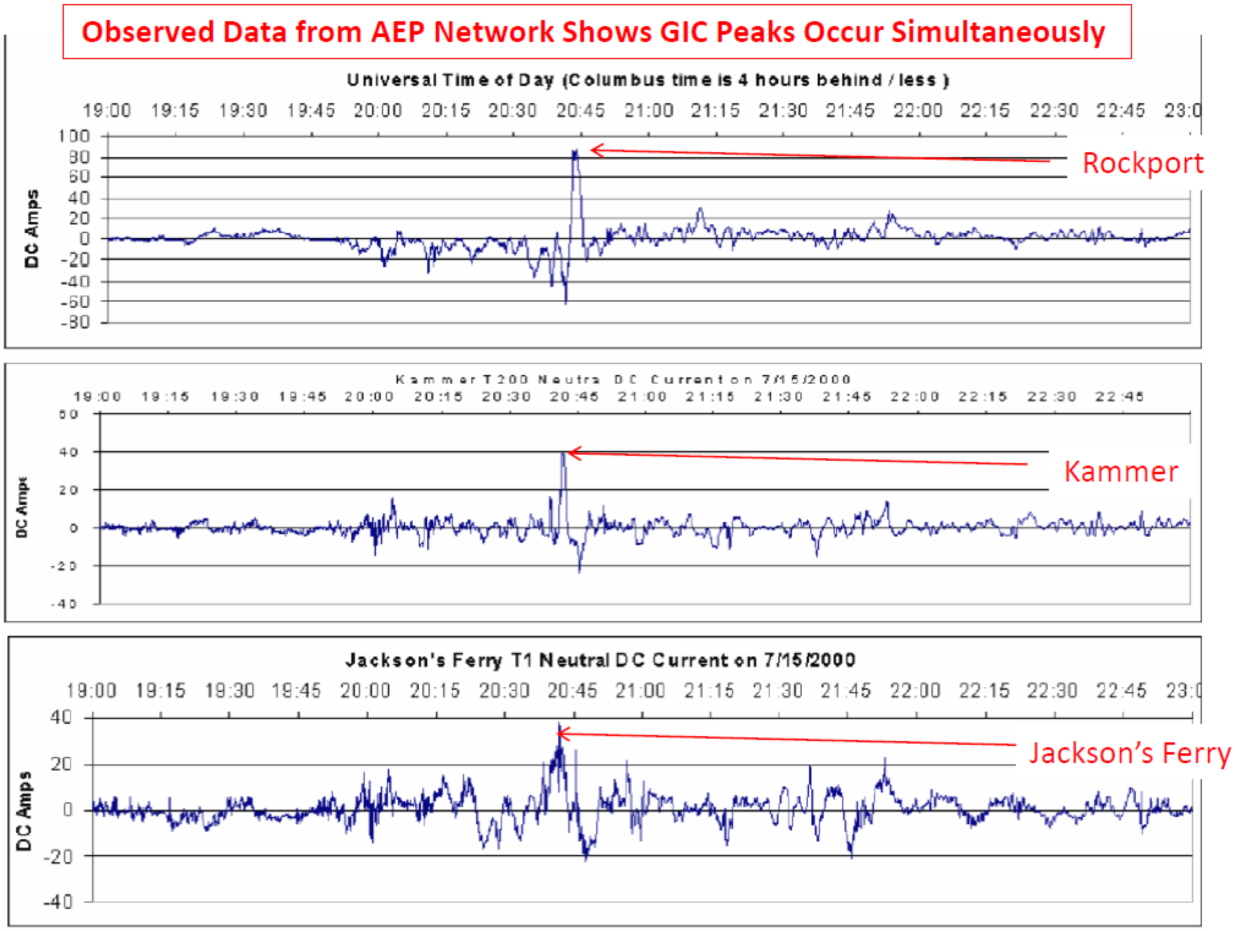
In this comment, we present data to show the NERC "hotspot" conjecture is inconsistent with real-world observations and the "Benchmark GMD Event" is therefore not scientifically well-founded.[2] Figures 1 and 2 show simultaneous GIC peaks observed at three transformers up to 580 kilometers apart, an exceedingly improbable event if NERC's "hotspot" conjecture were correct.

According to Faraday's Law of induction, geomagnetically induced current (GIC) is driven by changes in magnetic field intensity (dB/dt) in the upper atmosphere. If dB/dt peaks are observed simultaneously many kilometers apart, then it would follow that GIC peaks in transformers would also occur simultaneously many kilometers apart. Figure 3 shows simultaneous dB/dt peaks 1,760 kilometers apart during the May 4, 1988 solar storm.

In summary, the weight of real-world evidence shows the NERC "hotspot" conjecture to be erroneous. Simultaneous GIC impacts on the interconnected transmission system can and do occur over wide areas. The NERC Benchmark GMD Event is scientifically unfounded and should be revised by the Standard Drafting Team.

[1] See Appendix 1 for excerpts from the "Benchmark Geomagnetic Disturbance Event Description" whitepaper relating to NERC's "spatial averaging" conjecture.

[2] Data compilations in Figures 1 and 2 are derived from the AEP presentation given to the NERC GMD Task Force in February 2013. Figure 3 is derived from comments submitted to NERC in the Kappenman-Radasky Whitepaper.



GIC Peaks All Observed at Same Time: ~22:42 UT July 15, 2000

Figure 1. American Electric Power (AEP) Geomagnetically Induced Current Data Presented at February 2013 GMD Task Force Meeting

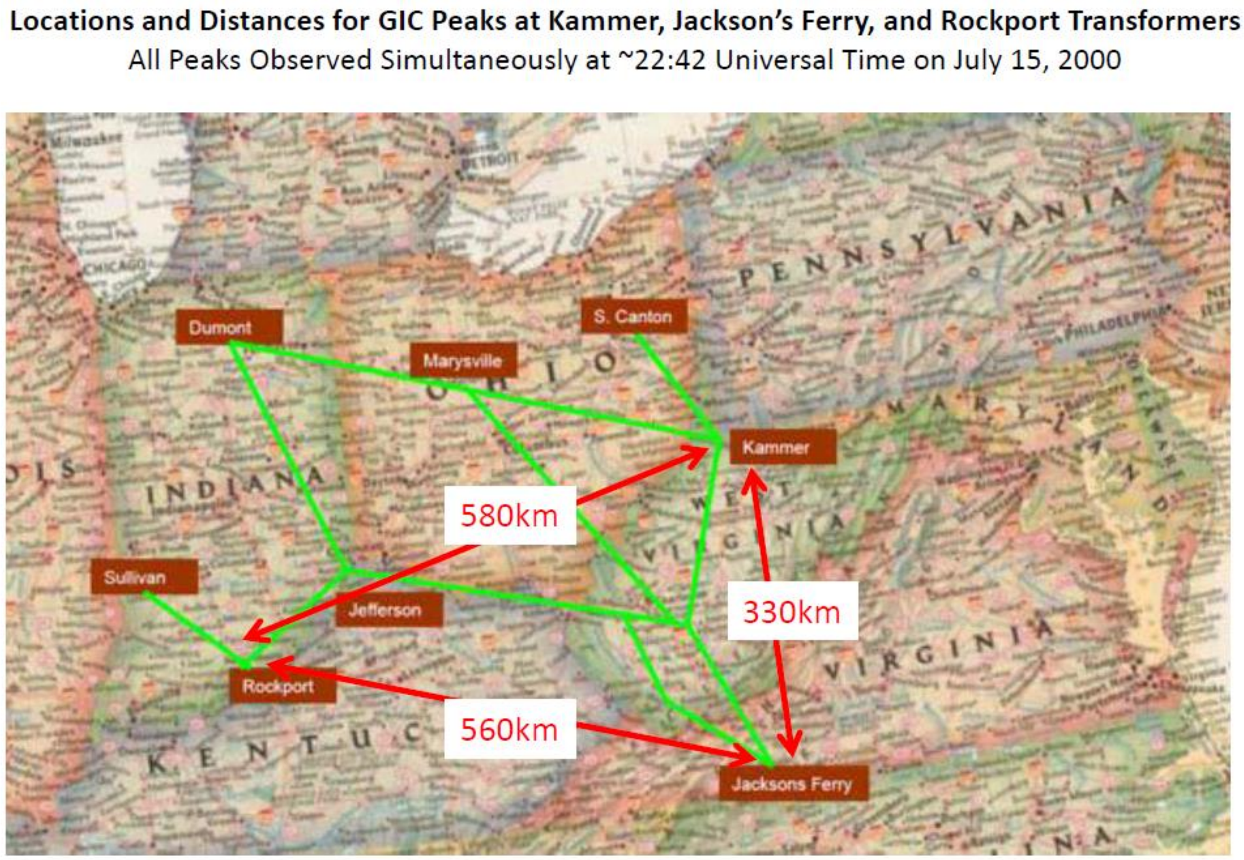


Figure 2. Location of Transformer Substations with GIC Readings on Map of States within AEP Network

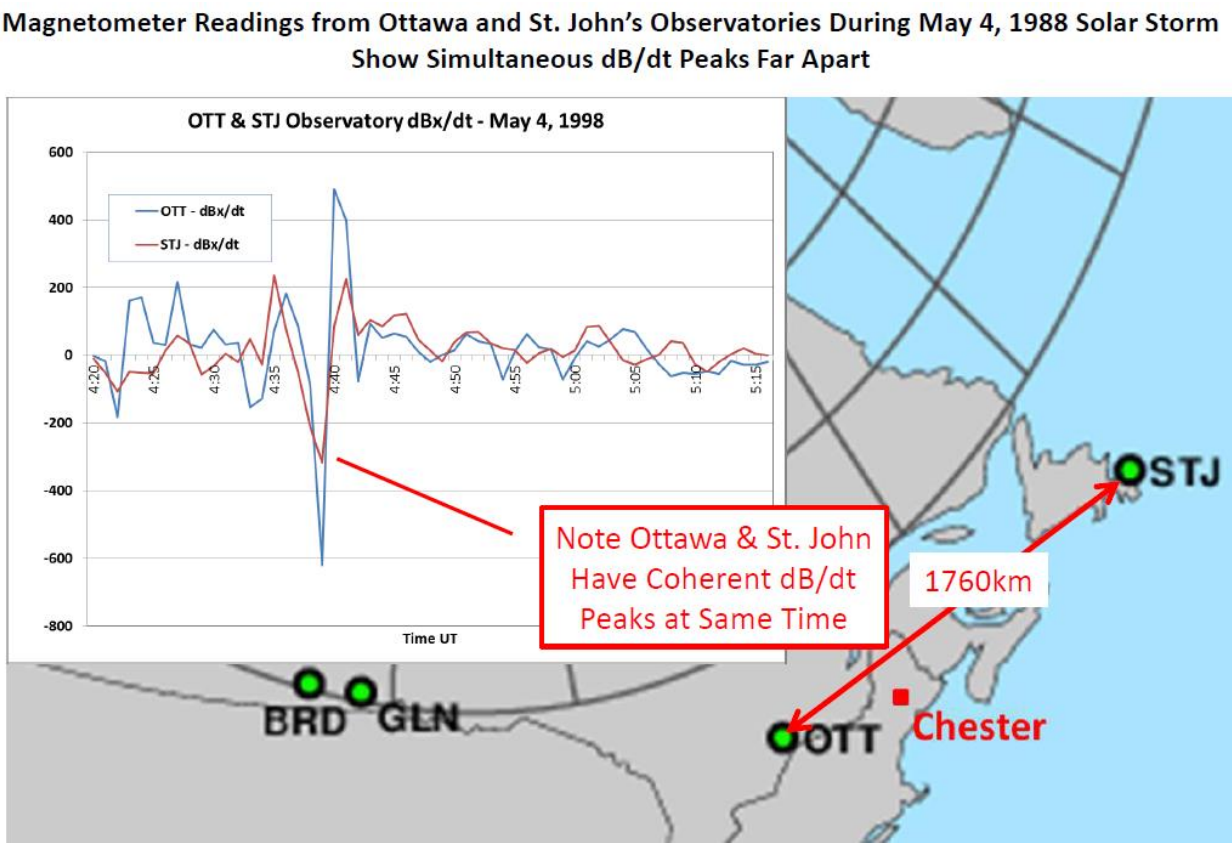


Figure 3. Magnetometer Readings Over Time from Ottawa and St. John Observatories

Appendix 1

Excerpts from
Benchmark Geomagnetic Disturbance Event Description

North American Electric Reliability Corporation

Project 2013-03 GMD Mitigation

Standard Drafting Team

Draft: August 21, 2014

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

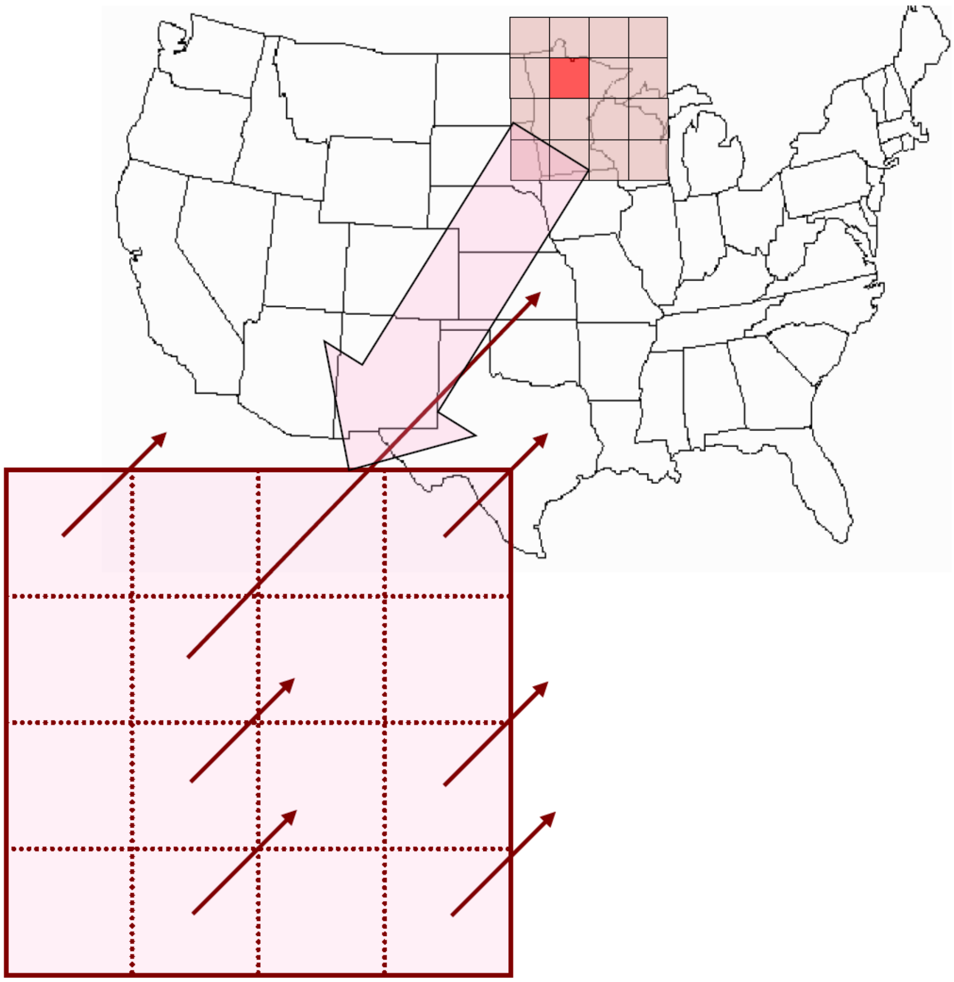


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

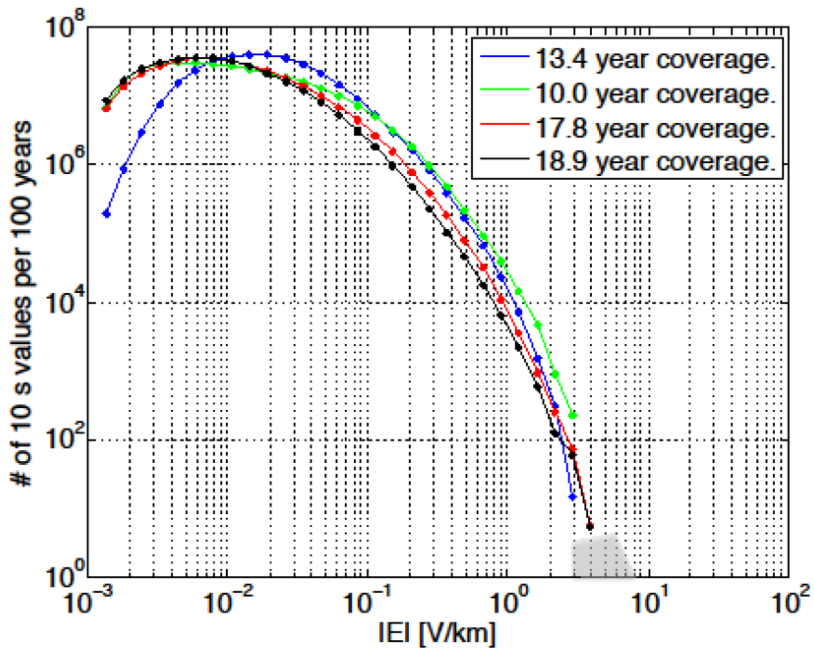


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

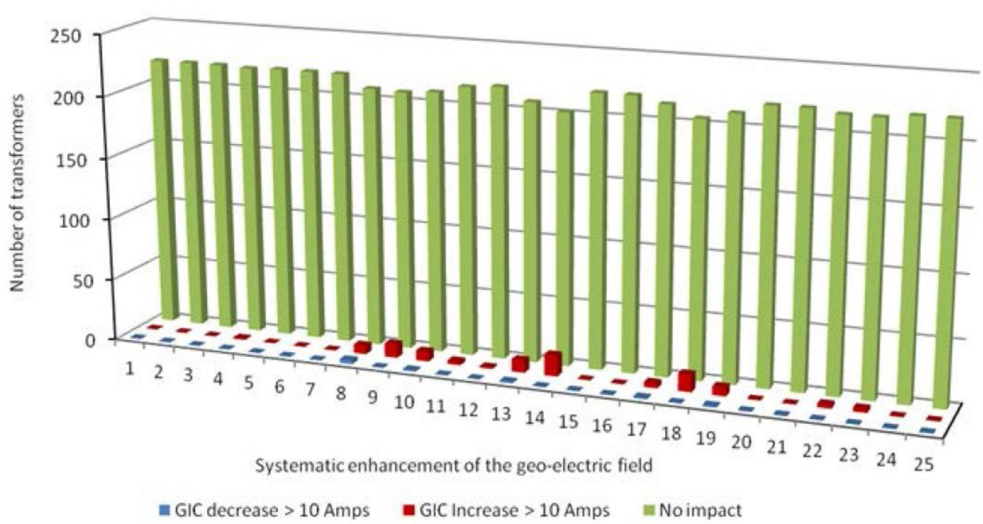


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1
Submitted to NERC on October 10, 2014

Executive Summary

The NERC Standard Drafting Team has proposed a Benchmark GMD Event based on a 1-in-100 year scenario that does not stand up to scrutiny, as data from just three storms in the last 40 years greatly exceed the peak thresholds proposed in this 100 Year NERC Draft Standard. The Standard Drafting Team then developed a model to estimate Peak Electric Fields (Peak E-Field) at locations within the continental United States for use by electric utilities that also has not been validated and appears to be in error. In these comments technical deficiencies are exposed in both the Benchmark GMD Event and the NERC E-Field model. These deficiencies include:

1. The NERC Benchmark GMD Event was developed using a data set from geomagnetic storm observations in Finland, not the United States.

2. The NERC Benchmark GMD Event was developed using a data set from a time period which excluded the three largest storms in the modern era of digital observations and does not include historically large storms.

3. The NERC Benchmark GMD Event excludes consideration of data recorded during geomagnetic storms in the United States in 1989, 1982, and 1972 that show the NERC benchmark is significantly lower than real-world observations.

4. While it is well-recognized that Peak dB/dt from geomagnetic storms vary according to latitude, observed real-world data from the United States shows that the NERC latitude scaling factors are too low at all latitudes. For storms observed over a 100 year period, NERC latitude scaling factors would be significantly more in error.

5. While it is well-recognized that Peak Electric Fields from geomagnetic storms vary according to regional ground conditions, observed real-world data from the United States shows that the NERC geo-electric field simulation models are producing results that are too low and may have embedded numerical inaccuracies.

6. When the estimated E-Field from the NERC model is compared to E-Field derived from measured data at Tillamook, Oregon during the Oct 30, 2003 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 5.

7. When the estimated E-Field from the NERC model is compared to the E-Field derived from measured data at Chester, Maine during the May 4, 1998 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 2.

8. The errors noted in points 5 and 6 become compounded when combined to determine the NERC Epeak levels for any location. The erroneous NERC latitude scaling factor, and the erroneous NERC geo-electric field model are multiplied together which compounds the errors in each part and produces an enormous escalation in overall error. In the case of Tillamook, it produces results too low by a factor of 30 when compared with measured data.

9. The NERC Benchmark GMD Event, NERC latitude scaling factors, and the NERC geo-electric field model do not use available data from over 100 Geomagnetically-Induced Current monitoring locations within the United States.

In conclusion, the NERC Standard has been defectively drafted because the Standard Drafting Team has chosen to use data from outside the United States and which excludes important storm events to develop its models instead of better and more complete data from within the United States or over more important storm events. GIC data in particular is in the possession of electric utilities and EPRI but not disclosed or utilized by NERC for standard-setting and independent scientific study. The resulting NERC models are systemically biased toward a geomagnetic storm threat that is far lower than has been actually observed and could have the effect of exempting United States electric utilities taking appropriate and prudent mitigation actions against geomagnetic storm threats.

The circumstances presented by this NERC standard development process are extraordinarily unusual, to say the least. Any other credible standards development organization that has ever existed would want to take into consideration all available data and observations and perform a rigorous as possible examination to guide their findings, fully test and validate simulation models etc. Yet this NERC Standards Development Team has decided to not even bother to gather and look at enormously important and abundant GIC data and develop useful interpretations and guidance that this data would provide. NERC has also refused to gather known data on other transformer failures or recent power system incidents that might be associated with geomagnetic storm activity. NERC has developed findings and standards that are entirely based upon untested and un-validated models, models which have also been called into question. These models further put forward results that in various ways actually contradict and ignore the laws of physics. The NERC Standard Development Team behavior parallels to an agency responsible for public safety like the NTSB refusing to look at airplane black box recorder data or to visit and inspect the crash evidence before making their recommendations for public safety. Such behaviors would not merit public trust in their findings.

Discussion of Inadequate Reference Field Storm Peak Intensity and Geomagnetic Field Scaling Factors

As Daniel Baker and John Kappenman had noted in their previously submitted comments in May 2014, there have been a number of observations of geomagnetic storm peaks higher than those in the NERC proposed in TPL-007-1 Reference Field Geomagnetic Disturbance[1]. The purpose of this filing is to further elaborate upon the NERC Draft Standard inadequacies and to also propose a new framework for the GMD Standard.

It is the role of Design Standards above all other factors to protect society from the consequences possible from severe geomagnetic storm events, this includes not only widespread blackout, but also widespread permanent damage to key assets such as transformers and generators which will be needed to provide for rapid post-storm recovery. It is clear that the North American power grid has experienced an unchecked increase in vulnerability to geomagnetic storms over many decades from growth of this infrastructure and inattention to the nature of this threat. In order for the standard to counter these potential threats, the standard must accurately define the extremes of storm intensity and geographic

[1] Daniel Baker & John Kappenman "Comments on NERC Draft GMD Standard TPL-007-1 – Problems with NERC Reference Disturbance and Comparison with More Severe Recent Storm Event", filed with NERC for Draft Standard TPL-007-1, May 2014

footprint of these disturbances. It is only then that the Standard would provide any measure of public assurance of grid security and resilience to these threats.

It is clear from the prior comments provided by a number of commenters that the NERC TPL-007-1 Draft Standard was not adequate to define a 1 in 100 year storm scenario and was not conservative as the NERC Standards Drafting Team claims. Further the NERC Standards Drafting team has not proceeded in their deliberations and developments of new draft standards per ANSI requirements. In developing the Draft 3 Standard now to be voted on and prior drafts, the Standard Drafting Team did not address multiple comments laying out technical deficiencies in the NERC storm scenario. According to the ANSI standard-setting process, comments regarding technical deficiencies in the standard must be specifically addressed.

Figure 1 provides a graphic illustration of the NERC Standard proposed geomagnetic field intensity in nT/min, adapted from Table II-1 of α "Alpha" scaling of the geomagnetic field versus latitude across North America[2].

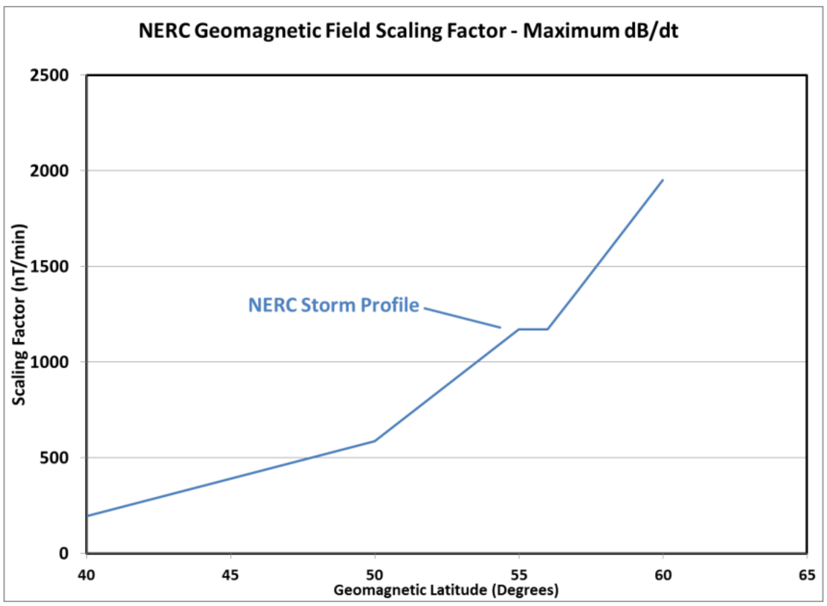


Figure 1 - NERC Proposed Profile of Geomagnetic Disturbance Intensity versus Geomagnetic Latitude

NERC has developed the intensity and profile described in Figure 1 from statistical studies carried out using recent data from the Image Magnetic observatories located in Finland and other Baltic locations[3]. This data base is a very small subset of observations of geomagnetic storm events, it is limited in time and does not include the largest storms of the modern digital data era and is limited in geography as it only focuses on a very small geographic territory at very high latitudes. The lowest latitude observatory in the Image array is at a geomagnetic latitude approximately equivalent to the US-Canada border, so this data set would not be able to explore the profile at geomagnetic latitudes below 55^{o} and therefore reliably characterize the profile across the bulk of the US power grid. The NERC Reference Field excludes the possibility of a Peak disturbance intensity of greater than 1950 nT/min and further excludes that the peak could occur at geomagnetic latitudes lower than 60^{o}. As observation data and other scientific analysis will show, both of these NERC exclusions are in error.

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[2] Page 20 of NERC Benchmark Geomagnetic Disturbance Event Description, April 21, 2014.

[3] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

For the NERC Reference profile of Figure 1 to be considered a conservative or 1 in 100 year reference profile, then no recent observational data from storms should ever exceed the profile line boundaries. However as previously noted, the statistical data used by NERC excluded world observations from the large and important March 1989 storm and also from two other important storms that took place in July 1982 and August 1972, a time period that only covers the last ~40 years. In addition, data developed from analysis of older and larger storms such as the May 1921 storm have been excluded by NERC in the development of this reference profile. In just examining the additional three storms of August 4, 1972, July 13-14, 1982, and March 13-14, 1989, a number of observations of intense dB/dt can be cited which exceed the NERC profile thresholds. Figure 2 provides a summary of these observed dB/dt intensities and geomagnetic latitude locations that exceed the NERC reference profile.

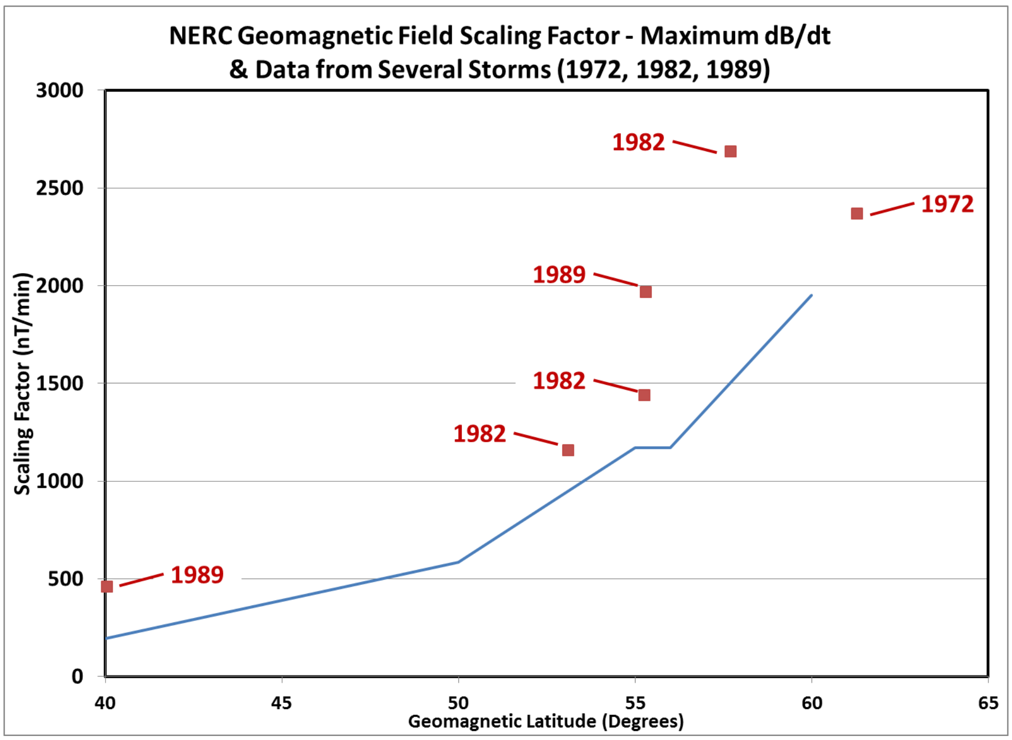

Figure 2 – NERC 100 Year Storm Reference Profile and Observations od dB/dt in 1972, 1982 and 1989 Storms that exceed the NERC Reference Profile

As Figure 2 illustrates that are a number of observations that greatly exceed the NERC reference profile at all geomagnetic latitudes in just these three storms alone. The geomagnetic storm process in part is driven by ionospheric electrojet current enhancements which expand to lower latitudes for more severe storms. The NERC Reference profile precludes that reality by confining the most extreme portion of the storm environment to a 60^o latitude with sharp falloffs further south. This NERC profile will not agree with the reality of the most extreme storm events. The excursions above the NERC profile boundary as displayed in Figure 2 clearly points out these contradictions.

In terms of what this implies for the North American region, a series of figures have been developed to illustrate the NERC reference field levels at various latitudes and actual observations that exceed the NERC reference thresholds. Figure 3 provides a plot showing via a red line the ~55^o geomagnetic latitude across North America which extends approximately across the US/Canada border. Along this boundary, the NERC Reference profile sets the Peak disturbance threshold at 1170 nT/min, but when considering the three storms not included in the NERC statistics database, it is clear that peaks of ~2700 nT/min have been observed at these high latitudes over just the past ~40 years. As will be discussed later, it is also understood that extremes up to ~5000 nT/min can occur down to these latitudes. Figure 4 provides a similar map showing the boundary at 53° geomagnetic latitude across the US and per the NERC Reference profile, the peak threat level would be limited to 936 nT/min. Yet at this same latitude at the Camp Douglas Station geomagnetic observatory, a peak dB/dt of ~1200 nT/min was observed during the July 1982 storm. Figure 5 provides a map showing the boundary at 40° geomagnetic latitudes and the NERC Reference peak at this location of only 195 nT/min. This figure also notes that in the March 1989 storm the Bay St. Louis observatory observed a peak dB/dt of 460 nT/min, this is 235% larger than the NERC peak threshold.

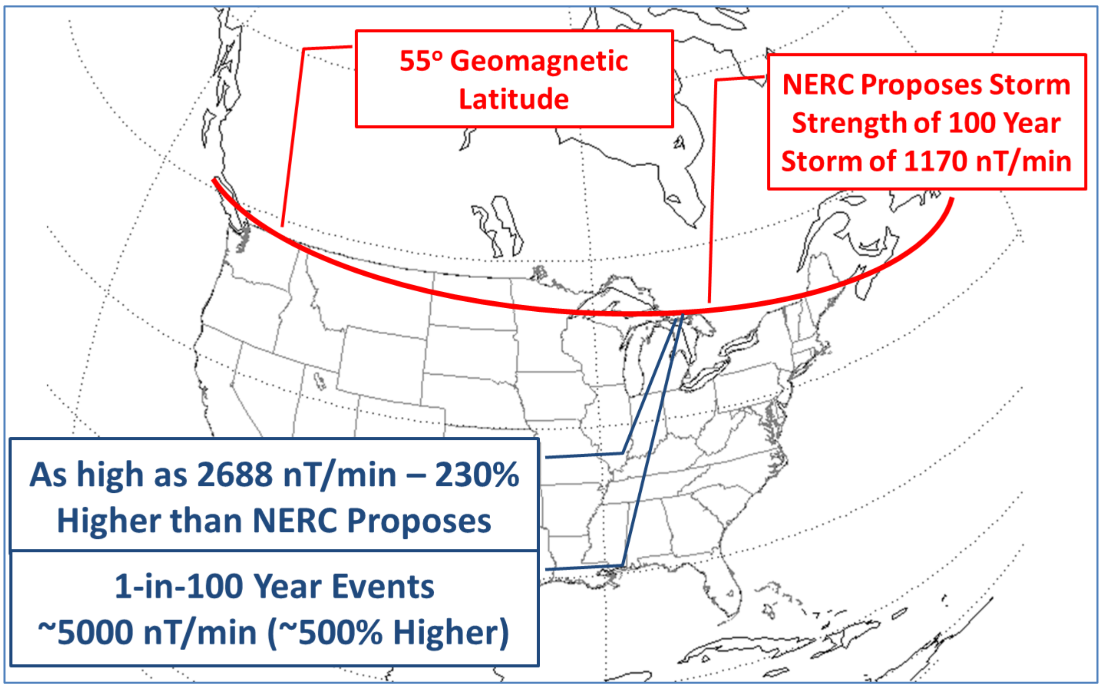

Figure 3 – Comparison of NERC Peak at 55° Latitude versus Actual Observed dB/dt

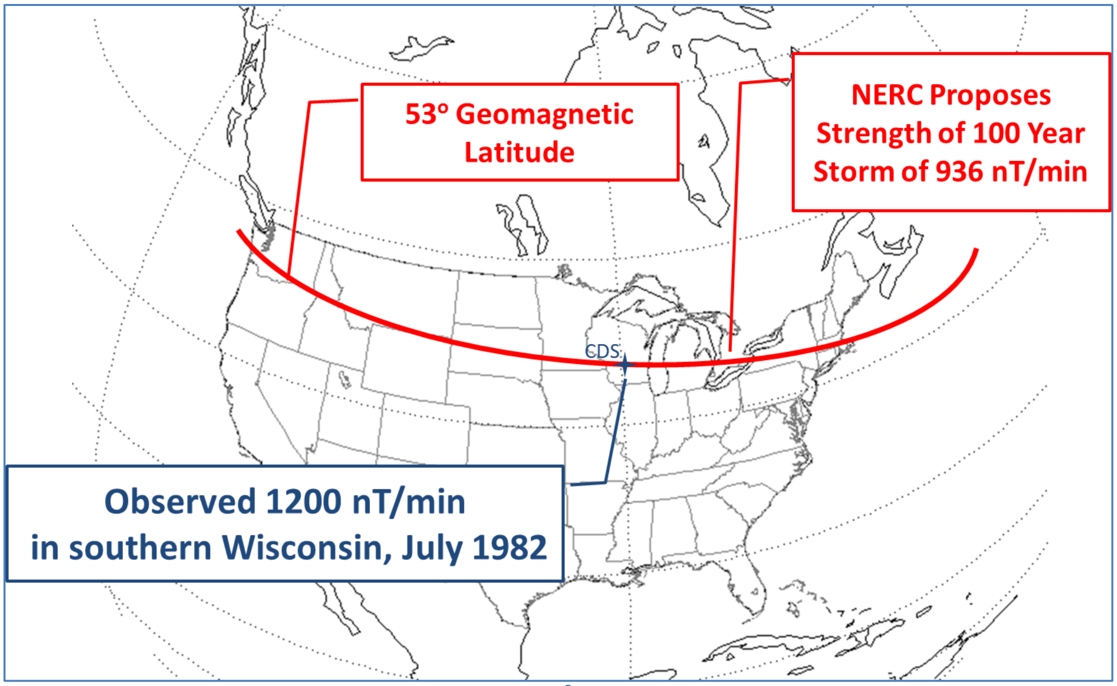

Figure 4 - Comparison of NERC Peak at 53° Latitude versus Actual Observed dB/dt

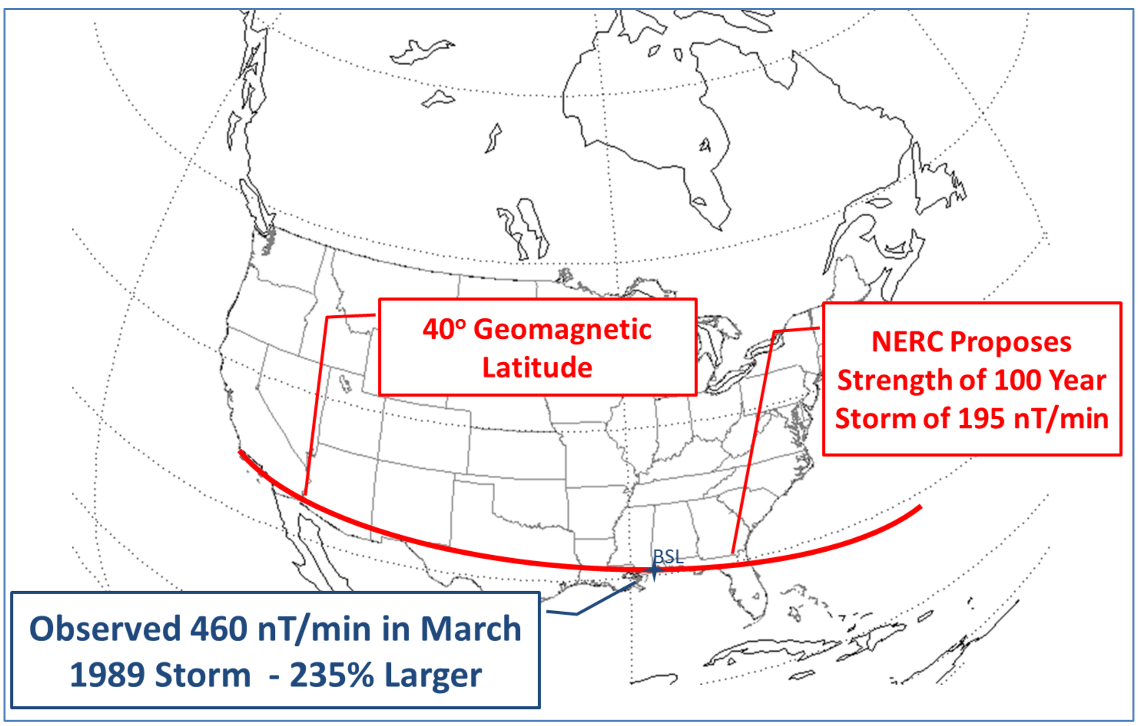

Figure 5 - Comparison of NERC Peak at 40° Latitude versus Actual Observed dB/dt

In summary, these storm observations limited to just three specific storms which happen to fall outside the NERC statistical database all show observations which exceed the NERC Reference profile at all latitudes. This illustrates that the NERC Reference profile cannot be a 1 in 100 year storm reference waveform and is not conservative. It should also be noted that even these three storm events are not representative of the worst case scenarios. In an analysis limited to European geomagnetic observatories, a science team publication concludes “there is a marked maximum in estimated extreme

levels between about 53 and 62 degrees north" and that "horizontal field changes may reach 1000-4000 nT/minute, in one magnetic storm once every 100 years"[4]. One advantage of this European analysis, it did not exclude data from older storms like the March 1989 and July 1982 storms, unlike in the case of the NERC database statistical analysis. In another publication the data from the May 1921 storm is assessed with the following findings; "In extreme scenarios available data suggests that disturbance levels as high as ~5000 nT/min may have occurred during the great geomagnetic storm of May 1921"[5]. In another recent publication, the authors conclude the following in regards to the lower latitude expansion of peak disturbance intensity; "It has been established that the latitude threshold boundary is located at about 50–55 of MLAT"[6]. It should be noted that one of the co-authors of this paper is also a member of the NERC Standards drafting team. All of these assessments are in general agreement and all call into question the NERC Reference Profile. Figure 6 provides a comparison plot of these published results with respect to the NERC Draft Standard profile and illustrates the significant degree of inadequacy the NERC Reference profile provides compared to these estimates of 100 Year storm extremes.

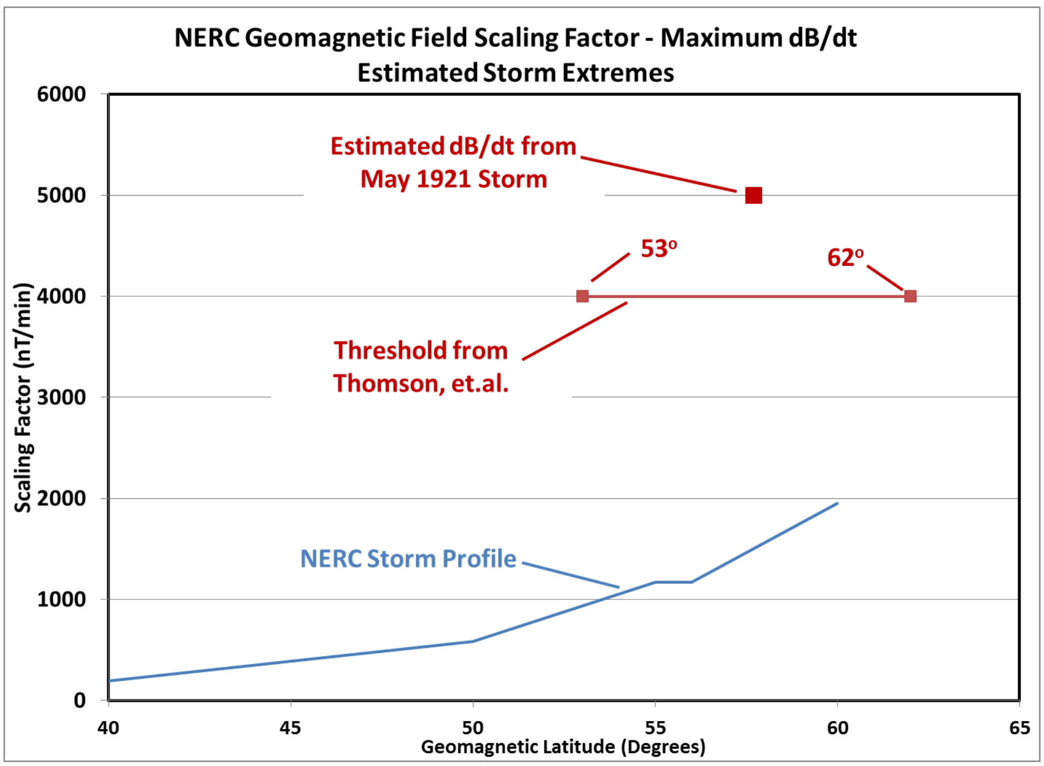

Figure 6 – Scientific Estimates of Extreme Geomagnetic Storm Thresholds compared to Propose3d NERC Draft Standard Profile

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[4] Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, Space Weather, 9, S10001, doi:10.1029/2011SW000696, 2011.

[5] John G. Kappenman, Great Geomagnetic Storms and Extreme Impulsive Geomagnetic Field Disturbance Events – An Analysis of Observational Evidence including the Great Storm of May 1921, Advances in Space Research, August 2005 doi:10.1016/j.asr.2005.08.055

[6] Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, Space Weather, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013.

Discussion of Inadequate Geo-Electric Field Peak Intensity

As the prior section of this discussion illustrates, the Peak Intensity of the proposed NERC geomagnetic disturbance reference field greatly understates a 100 year storm event. In prior comments submitted, it was also discovered that the geo-electric field models that NERC has proposed will also understate the peak geo-electric field[7]. In developing the Peak Geo-electric field, NERC has proposed the following formula:

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

Figure 7 – NERC Peak Geo-Electric Field Formula

As discussed in the last section of these comments the α (Alpha) factor in the above formula is understated at all latitudes for the NERC 100 year storm thresholds. In addition, the White Paper illustrates that the NERC proposed β (Beta) factor will also understate the geo-electric field by as much as a factor of 5 times the actual geo-electric field. When these two factors are included and multiplied together in the same formula, this acts to compound the individual understatements of the α and β factors into a significantly larger understatement of Peak Geo-electric field.

This compounding of errors in the α and β factors can be best illustrated from a case study provided in the Kappenman/Radasky White Paper. In this paper, Figure 27 (page 26) provides the geo-electric field recorded at Tillamook Oregon during the Oct 30, 2003 storm. Also shown is the NERC Model calculation for the same storm at this location. As this comparison illustrates, the NERC model understates the actual geo-electric field by a factor of ~5 and that the actual peak geo-electric field during this storm is nearly 1.2 V/km. Further this geo-electric field is being driven by dB/dt intensity at Victoria (about 250km north from Tillamook) that is 150 nT/min. Tillamook is also at ~50 geomagnetic latitude, so it is possible that the 100 year storm intensity could reach 5000 nT/min or certainly much higher than 150 nT/min. When using the NERC formula to calculate the peak Geo-electric field at Tillamook, the following factors would be utilized as specified in the NERC draft standard: For Tillamook Location, the α Alpha Factor = 0.3 based on Tillamook being at ~50 degrees MagLat, the β Beta Factor = 0.62 for PB1 Ground Model at Tillamook. Then using the NERC formula the derived Epeak would be:

"Tillamook Epeak" = 8 x 0.3 x 0.62 = 1.488 V/km (from NERC Epeak Formula)

In comparison to the ~1.2 V/km observed during the Oct 2003 storm, this NERC-derived Peak is nearly at the same intensity as caused by a ~150 nT/min disturbance. The scientifically sound method of deriving the Peak intensity is to utilize Faraday's Law of Induction to estimate the peak at higher dB/dt intensities. Faraday's Law of Induction is Linear (assuming the same spectral content for the disturbance field), which requires that as dB/dt increases, the resulting Geo-Electric Field also increases linearly. Therefore using the assumption of a uniform spectral content, which may be understating the threat environment, extrapolating to a 5000 nT/min peak environment would project a Peak Geo-Electric Field of ~40 V/km, a Factor of ~30 times higher than derived from the NERC Epeak Formula[8].

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[7] John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.

[8] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/150) = 33.3, Peak Electric = 1.2 V/km *33.3 = 40 V/km

A similar derivation can be performed for the GIC and geo-electric field observations at Chester Maine in the White Paper. From Figure 14 (page 17) the dB/dt in the Chester region reached a peak of ~600 nT/min and resulted in a ~2V/km peak geo-electric field during the May 4, 1998 storm. For this case study, the proposed NERC standard and the formula for the Peak Geo-Electric Field using the following factors for the Chester location, the Alpha Factor = 0.6 based on Chester being at ~55^{o} MagLat, the Beta Factor = 0.81 for NE1 Ground Model at Chester. The NERC Formula would derive the Peak being only ~3.88 V/km.

"Chester Epeak" = 8 x 0.6 x 0.81 = 3.88 V/km (from NERC Epeak Formula)

In contrast to the NERC Epeak value, a physics-based calculation can be made for the case study of the May 4, 1998 storm at Chester. Again, Faraday's Law of Induction can be utilized to extrapolate from the observed 600 nT/min levels to a 5000 nT/min threshold. This results in a Peak Geo-Electric Field of ~16.6 V/km, a Factor of ~4.3 higher than derived from the NERC Formula[9].

Discussion of Data-Based GMD Standard to Replace NERC Draft Standard

As prior sections of this discussion has revealed, the proposed NERC Draft Standard does not accurately describe the threat environment consistent with a 1-in-100 Year Storm threshold, rather the NERC Draft Standard proposes storm thresholds that are only a 1-in-10 to 1-in-30 Year frequency of occurrence. Further, the methods proposed by NERC to estimate geo-electric field levels across the US are not validated and where independent assessment has been performed the NERC Geo-Electric Field levels are 2 to 5 times smaller than observed based on direct GIC measurements of the power grid.

Basic input assumptions on ground conductivity used in the NERC ground modeling approach have never been verified or validated. Ground models are enormously difficult to characterize, in that for the frequencies of geomagnetic field disturbances, it is necessary to estimate these profiles to depths of 400kM or deeper. Direct measurements at these depths are not possible to carry out and the conductivity of various rock strata can vary by as much as 200,000%, creating enormous input modeling uncertainties for these ground profiles. Further it has been shown that the NERC geo-electric field modeling calculations themselves appear to have inherent frequency cutoff's that produce underestimates of geo-electric fields as the disturbance increases in intensity and therefore importance. Hence the NERC Standard is built entirely upon flawed assumptions and has no validations.

A framework for a better Standard which is highly validated and accurate has been provided via the Kappenman/Radasky White Paper and the discussion provided in these comments. As noted in the White Paper, the availability of GIC data and corresponding geomagnetic field disturbance data allowed highly refined estimates to be performed for geo-electric fields and to extrapolate the Geo-Electric Field to the 100 Year storm thresholds for these regions. The primary inputs (other than GIC and corresponding geomagnetic field observations) are simply just details on the power grid circuit parameters and circuit topology. These parameters are also known to very high precision (for example transmission line resistance is known to 4 significant digits after the decimal point). Asset locations are

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[9] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/600) = 8.3, Peak Electric = 2 V/km *8.3 = 16.6 V/km

also known with high precision and many commercially available simulation tools can readily compute the GIC for a uniform 1 V/km geo-electric field. This calculation provides an intrinsic GIC flow benchmark that can be used to convert any observed GIC to an regionally valid Geo-Electric Field that produced that GIC. Further this calculation is derived over meso-scale distances on the actual power grid assets of concern. As summarized in a recent IEEE Panel discussion, this approach allows for wide area estimates of ground response than possible from conventional magneto-telluric measurements[10]. Figure 8 provides a map showing the locations of the Chester, Seabrook and Tillamook GIC observations and the approximate boundaries based upon circuit parameters of the ground region that were validated.

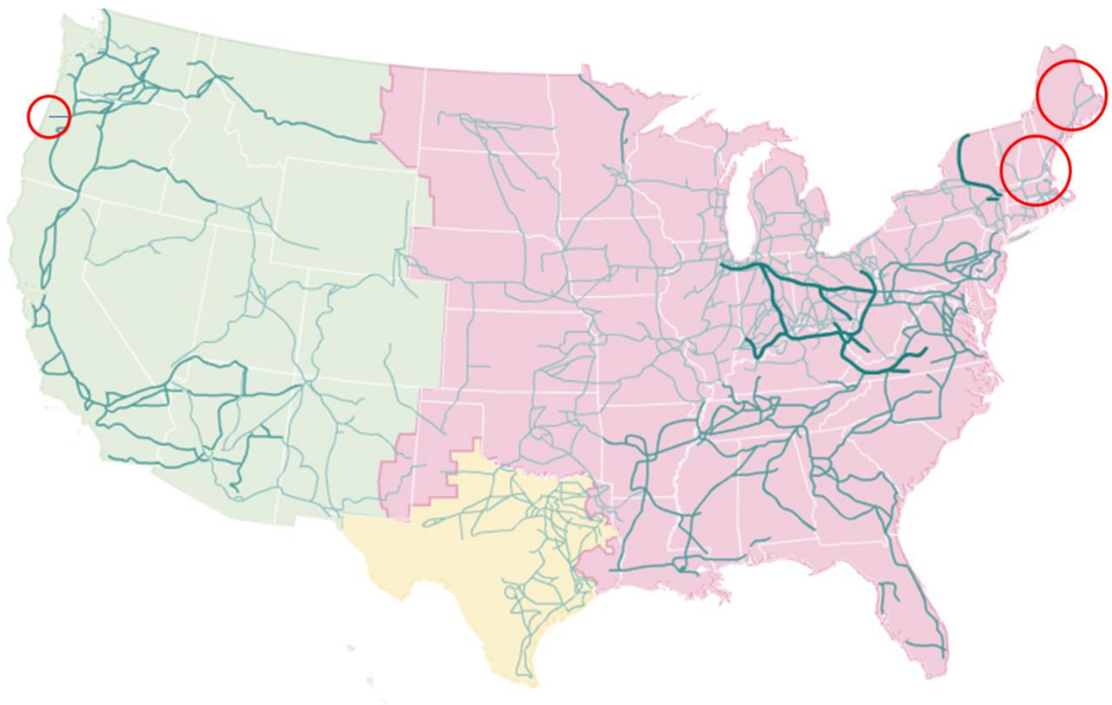

Figure 8 – Red Circles provide Region of Ground Model Validation using GIC observations from Kappenman/Radasky White Paper.

As filed in a recent FERC Docket filing[11], ~100 GIC monitoring sites have operated and are collecting data across the US. Using these analysis techniques and the full complement of GIC monitoring locations, it is possible to accurately benchmark major portions of the US as shown in the map in Figure 9. As shown in this figure, the bulk of the Eastern grid is covered and in many locations with overlapping benchmark regions, such that multiple independent observations can be used to confirm the accuracy of the regional validations. The same is also true for much of the Pacific NW. As noted in Meta-R-319 and shown below is Figure 10 from that report, these two regions are the most at-risk regions of the US Grid.

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[10] Kappenman, J.G., "An Overview of Geomagnetic Storm Impacts and the Role of Monitoring and Situational Awareness", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[11] Foundation for Resilient Societies, "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND", Docket No. RM14-1-000, submitted to FERC on August 18, 2014.

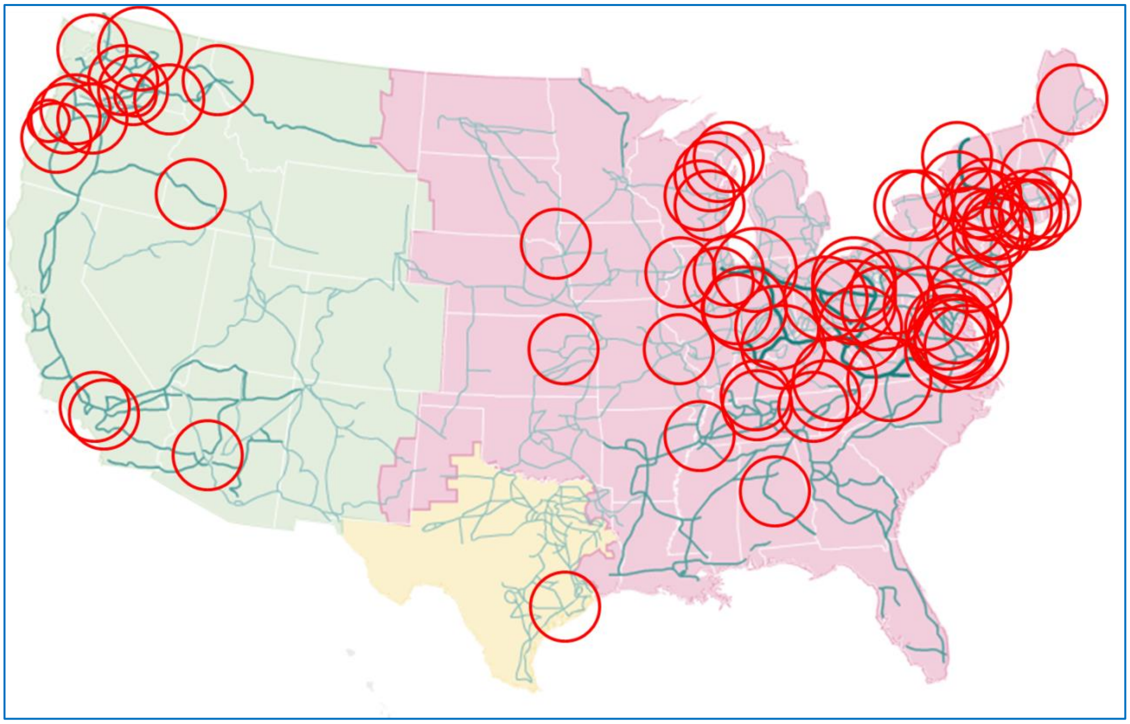


Figure 9 – GIC Observatories and US Grid-wide validation regions.

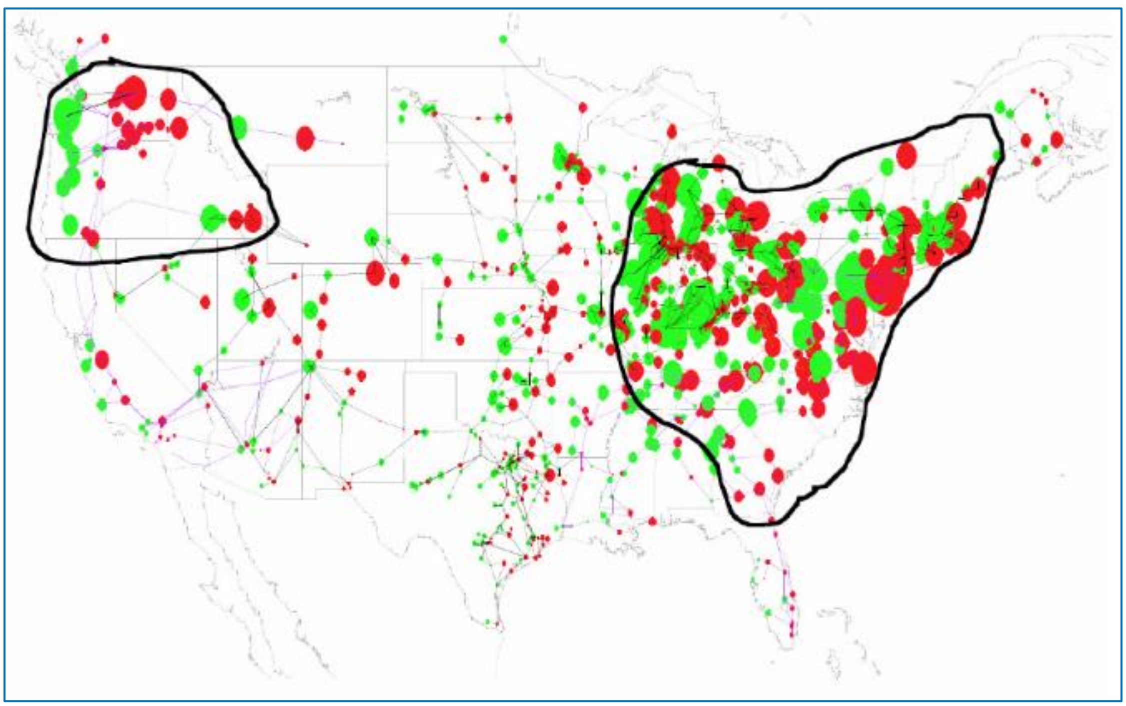


Figure 10 – Map of At-Risk Regions from Meta-R-319 Report for 50° Severe Storm Scenario

Each of these GIC measurements can define and validate the geo-electric field parameters over considerable distance. In the example of the Chester Maine case study, the validations in the case of the 345kV system can extend ~ 250kM radius. At higher kV ratings, the footprint of GIC and associated geo-electric field measurements integrates over an even larger area. As these measurements are accumulated over the US, the characterizations provide a very complete coverage with many

overlapping coverage confirmations. These confirmations will also have Ohm's law degree of accuracy, whereas magnetotelluric observations can still have greater than factor of 2 uncertainty[12]. For those areas where perhaps a GIC observation is not available, this region can utilize a base intensity level that agrees with neighboring systems until measurements can be made available to fully validate the regional characteristics.

This Observational-Based Standard further establishes a more accurate framework for developing the standard using facts-based GIC observation data as well as the laws of physics[13], and removes the dependence on simulation models which could be in error. The power system and GIC flows observed on this system will always obey the laws of physics while models may exhibit erratic behaviors and are dependent on the skill/qualifications of the modeler and the uncertainty of model inputs. Models are always inferior to actual data as they cannot incorporate all of the factors involved and can have biases which can inadvertently introduce errors. This Observational Framework methodology is also open and transparent so any and all interested parties can review and audit findings. The validations can be performed quickly and inexpensively across all of these observational regions. It also allows for simple updates once new transmission changes are made over time as well.

Respectfully Submitted by,

John Kappenman, Principal Consultant
Storm Analysis Consultants

Curtis Birnbach, President and CTO
Advanced Fusion Systems

[12] Boteler, D., "The Influence of Earth Conductivity Structure on the Electric Fields that drive GIC in Power Systems", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[13] For example, Ohm's Law and Faraday's Law of Induction

EIS Council Comments on Benchmark GMD Event

TPL-007-1

Submitted on October 10, 2014

Introduction

The Electric Infrastructure Security Council's mission is to work in partnership with government and corporate stakeholders to host national and international education, planning and communication initiatives to help improve infrastructure protection against electromagnetic threats (e-threats) and other hazards. E-threats include naturally occurring geomagnetic disturbances (GMD), high-altitude electromagnetic pulses (HEMP) from nuclear weapons, and non-nuclear EMP from intentional electromagnetic interference (IEMI) devices.

In working to achieve these goals, EIS Council is open to all approaches, but feels that industry-driven standards, as represented by the NERC process, are generally preferable to government regulation. That said, government regulation has proven necessary in instances (of all kinds) when a given private sector industry does not self-regulate to levels of safety or security acceptable to the public. EIS Council is concerned that the new proposed GMD benchmark event represents an estimate that is too optimistic, and would invite further regulatory scrutiny of the electric power industry.

The proposed benchmark GMD event represents a departure from previous GMDTF discussions, where the development of the "100-year" benchmark GMD event appeared to be coming to a consensus, based upon statistical projections of recorded smaller GMD events to 100-year storm levels. These levels of 10 – 50 V/km, with the average found to be 20 V/km, were also in agreement with what were thought to be the storm intensity levels of the 1921 Railroad Storm, which, along with the 1859 Carrington Event, were typically thought to be the scale of events for which the NERC GMDTF was formed to consider.

The new approach described in April 14, 2014 Draft (and subsequent GMDTF meetings and discussions) contains several key features that EIS Council does not consider to yet have enough scientific rigor to be supported, and would therefore recommend that a more conservative or "pessimistic" approach should be used to ensure proper engineering safety margins for electric grid resilience under GMD conditions. These are:

1. The introduction of a new "spatial averaging" technique, which has the effect of lowing the benchmark field strengths of concern from 20 V/km to 8 V/km;

2. A lack of validation of this new model, demonstrating that it is in line with prior observed geoelectric field values;

3. The use of the 1989 Quebec GMD event as the benchmark reference storm, rather than a larger known storm such as the 1921 Railroad storm;

4. The use of 60 degrees geomagnetic latitude as the storm center; and

5. The use of geomagnetic latitude scaling factors to calculate expected storm intensities south of 60 degrees.

Spatial Averaging and Model Validation

The introduction of the spatial averaging technique is a novel introduction to discussions of the GMDTF. While the concept could prove to have validity, the abrupt change to a new methodology at this time is not fully understood by the GMDTF membership, nor has it yet had any peer review by the larger space weather scientific community. In order to ensure confidence that this is a proper approach, it is necessary that this approach be validated with available data via the standard peer-review process.

Prior findings of the GMDTF of a 20 V/km peak field values were shown to be in line with prior benchmark storms such as the 1921 Railroad storm, for which there is very good magnetometer data across the United States and Canada. Even for the 1989 Quebec Storm, on which this new benchmark is supposed to be based, it is not clear whether the new spatial averaging technique has been demonstrated to be in line with the known magnetometer data. This would seem to be a fairly straightforward validation of this new model, but is currently lacking in the description of the new approach.

The spatial averaging method also appears to be at odds with standard engineering safety margin design approaches. As an example, if the maximum load for a bridge is 20 tons, but the average load is 8 tons, a bridge is designed to hold at least 20 tons, or more typically 40 tons, a factor of two safety margin over the reasonably expected maximum load. It is recommended that the screening criteria be increased to encompass the maximum credible storm event, rather than an average, in line with typically accepted best practices for engineering design.

The description of the method does describe that within the expected spatially-averaged GMD event of 8 V/km, that smaller, moving “hot spots” of 20 V/km are expected. It therefore seems prudent for electric power companies to analyze the expected resilience of their system against a 20 V/km geoelectric field, as any given company could find themselves within such a “hot spot” during a GMD event.

One further point to consider is that, while the GMDTF scope does not at present include EMP, the unclassified IEC standard for the geoelectric fields associated with EMP E3 is 40 V/km. Should the scope of the GMDTF or FERC order 779 ever be expanded to include EMP E3, 40 V/km is the accepted international standard, something to consider when setting the benchmark event, as any given power company could find themselves subject to the maximum credible EMP E3 field.

1989 Quebec Storm as the Benchmark Event

The 1989 Quebec Storm is very well-studied event, and is a dramatic example of the impacts of GMD on power grids. The loss of power in the Province of Quebec, failure of the Salem transformer, and other grid anomalies associated with the storm are all well documented. The GMDTF was formed, and FERC Order 779 issued, to ensure grid resilience for events that will be much larger than the 1989 Quebec Storm, such as the 1921 Railroad Storm. The two figures below show a side-by-side comparison of the 1989 and 1921 storms. The geographic size, and also the latitude locations are quite striking.

The use of the 1989 Quebec Storm as the benchmark event is of concern because simply scaling the field strengths of the 1989 Storm higher (an “intensification factor” of 2.5 is used), but leaving the same geographic footprint, does not appear to be a valid approach. While the 2.5 scaling factor is described to produce local “hot spots” of 20 V/km, in agreement with earlier findings, it fails to consider the well-known GMD phenomena that the electrojets of larger storms shift southward, as can be seen in comparing the two figures. By using the geographic footprint of the 1989 storm, the new benchmark will predict geoelectric field levels that are incorrect for geomagnetic latitudes below 60 degrees, where the center of the new benchmark storm has been set.

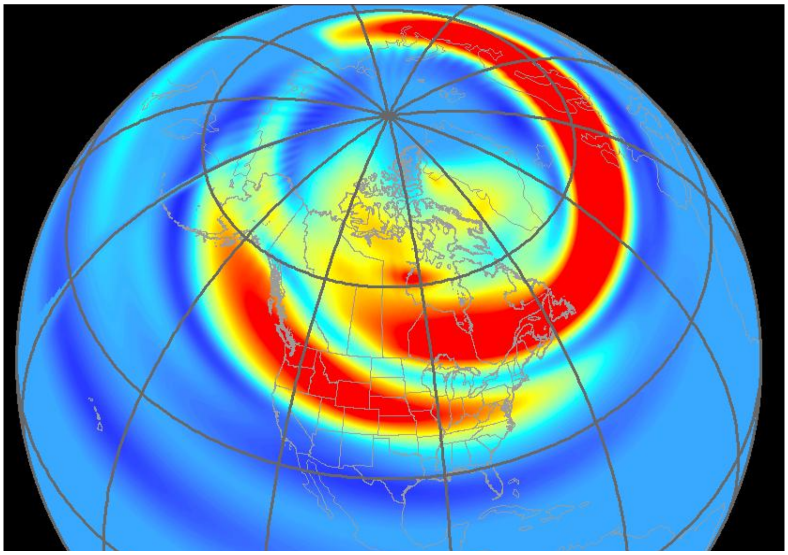


Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

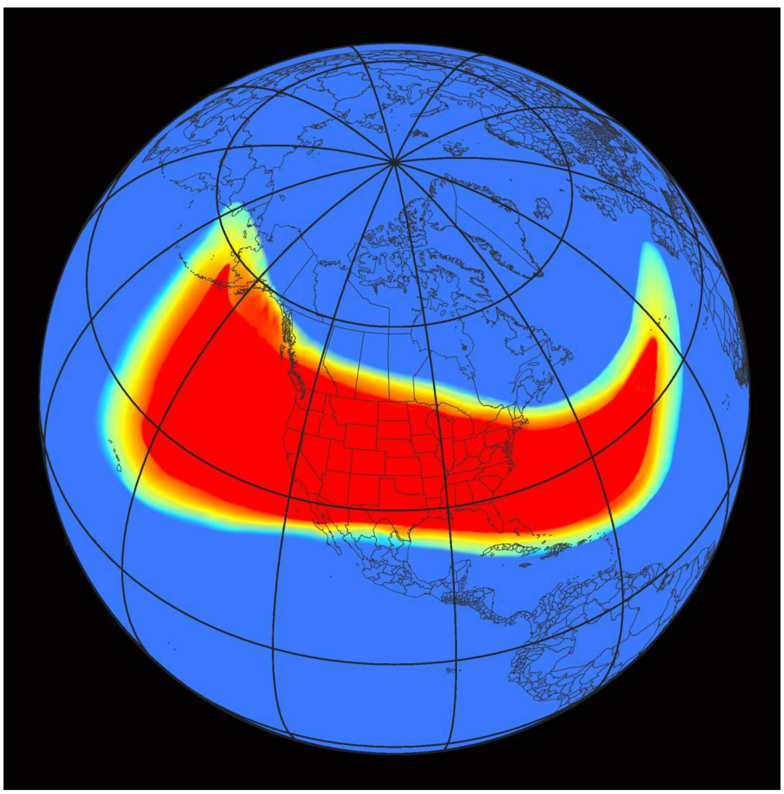


Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

As the figures above show, GMD events larger than the 1989 Quebec event are expected to be larger in overall geographic laydown (continental to global in scale), and also to be centered at lower geomagnetic latitudes than the 1989 storm, due to a southward shifting of the auroral electrojet for more energetic storms. While the latitudinal scaling factor α may be correct for a storm like the 1989 Storm and centered on 60 degrees geomagnetic latitude, use of these scaling factors does not appear to be valid for GMD events where the storm will be centered at a lower latitude, and have a larger geographic footprint. While the β factor - which captures differences in geologic ground conductivity - will remain valid under all storm scenarios, the α factors would only be valid for a storm centered at 60 degrees. For example, in looking at figure 2 above, the storm is quite large, and centered at (roughly) 40 – 45 degrees North Latitude. The correct α factor for 45 degrees in this case would be 1, rather than the 0.2 value that would be correct for a storm centered at 60 degrees North Latitude. As it is not known what the center latitude of any given storm center would be, it would seem that the use of the 60 degree storm center latitude and subsequent α scaling factors is not fully supported.

Supporting scientific evidence for the use of the 60-degree storm center and scaling factors is cited in TPL-007-1. The supporting paper by Ngwira et al[1], however, discusses a "latitude threshold boundary [that] is associated with the movements of the auroral oval and the corresponding auroral electrojet current system." The latitude boundary found in the paper, however, is given as 50 degrees magnetic latitude, rather than 60 degrees. The study determines this boundary based on observations of ~30 years of geomagnetic storm data. While the data set is large, it does not contain very large storms, on the scale of the 1921 Railroad storm. As the largest storms are known to have the largest southward electrojets shifts, it would seem prudent that the benchmark be adjusted to be consistent with the supporting scientific finding of 50 degrees magnetic latitude, and a subsequent re-calculation of the α scaling factors for latitudes below 50 degrees.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed

[1] Ngwira, Pulkkinen, Wilder, and Crowley, *Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications*, Space Weather, Vol. 11 121-131 (2013)

discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there would seem to be a scientific inconsistency in using a benchmark storm centered at 60 degrees geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location down to 50 degrees, as cited in the supporting document. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, centered at the cited 50 degree magnetic latitude threshold boundary, with subsequently updated latitude scaling factors for lower latitudes, as the benchmark event against which the individual electric power companies can analyze their system resilience.

<u>Comments on NERC TPL – 007 – 1 (R5)</u>

<u>Reference s*creening criterion for GIC Transformer Thermal Impact Assessment*</u>

<u>Issue</u>

A level of 15 Amps / phase was selected for this screening. It was based on temperature rise measurements of structural parts of some core form transformers reaching a level of 50 K upon application of 15 Amps / phase DC.

<u>Comment – 1</u>

Since the time constant of the transformer structural parts is typically in the 10 – minute range, these temperatures were reached after application of the DC current for 10's of minutes (up to 50 minutes in some cases). The high level GIC pulses are typically of much shorter duration and the corresponding temperature rise would be a fraction of these temperature rises.

<u>Recommendation</u>

Upon performing temperature calculations of the cases referenced in the NERC screening White paper for GIC pulses, we suggest the following:

1. The 15 Amps / phase could be kept as a screening criterion for GIC levels extending over; say, 30 minutes.
2. A higher level of 50 Amps / phase is used as a screening criterion for high – peak, short – duration pulses. A 3 – minute duration of 50 Amps would be equivalent to, and even more conservative than, the 15 Amps / phase steady state.

<u>Comment – 2</u>

The 15 Amps / phase level was based on measurements on transformers with core – types, other than 3 – phase, 3 – limb cores. Three Phase core form transformers with 3 – limb cores are less susceptible to core saturation.

<u>Recommendation</u>

We suggest that, for 3 – phase core form transformers with 3 – limb cores, a higher level of GIC, for example 30 or 50 Amps / phase, is selected for the screening level for the <u>base</u> GIC and correspondingly

a much higher level, for example, 100 Amps / phase, for the high – peak, short – duration GIC pulses.

Note 1:

The revised screening criterion recommended in the above, is not only more appropriate technically than what is presently suggested in the NERC "Thermal screening" document, but also will reduce the number of transformers to be thermally assessed probably by a factor of 10; which would make the thermal evaluation of the $\geq$ 200 kV transformer fleet in North America to be more feasible to be done in the time period required by the NERC document.

Note 2:

It is to be noted that proposing one value of GIC current for screening for all transformer types (core form vs. shell form), sizes, designs, construction, etc. is not technically correct. However, for the sake of moving the NERC document forward, we agreed to follow the same path but provide the improved criterion we recommended above.

Submitted by:

Mr. Raj Ahuja, Waukesha
Mr. Mohamed Diaby, Efacec
Dr. Ramsis Girgis, ABB
Mr. Sanjay Patel, Smit
Mr. Johannes Raith, Siemens

Comments on NERC TPL – 007 – 1 (R6)

"GIC Transformer Thermal Impact Assessment"

Issue

The document should have a Standard GIC signature to be used for the thermal impact Assessment of the power Transformer fleet covered by the NERC document.

Comment – 1

Users would not be able to predict, to any degree of accuracy, what GIC signature a transformer would be subjected to during future GMD storms. This is since the actual GIC signature will depend on the specific parameters and location of the future GMD storms. Unless a user requires thermal assessment of their fleet of transformers to actual GIC signatures, the user should be able to use a Standard GIC Signature; where the parameters of the signature (magnitudes and durations of the different parts of the signature) would be specified by the user.

This is parallel to the standard signatures used by the transformer / utility industry Standards (IEEE & IEC) for lightning surges, switching surges, etc.; where standard signatures (wave – shapes) are used for evaluating the dielectric capability of transformers.

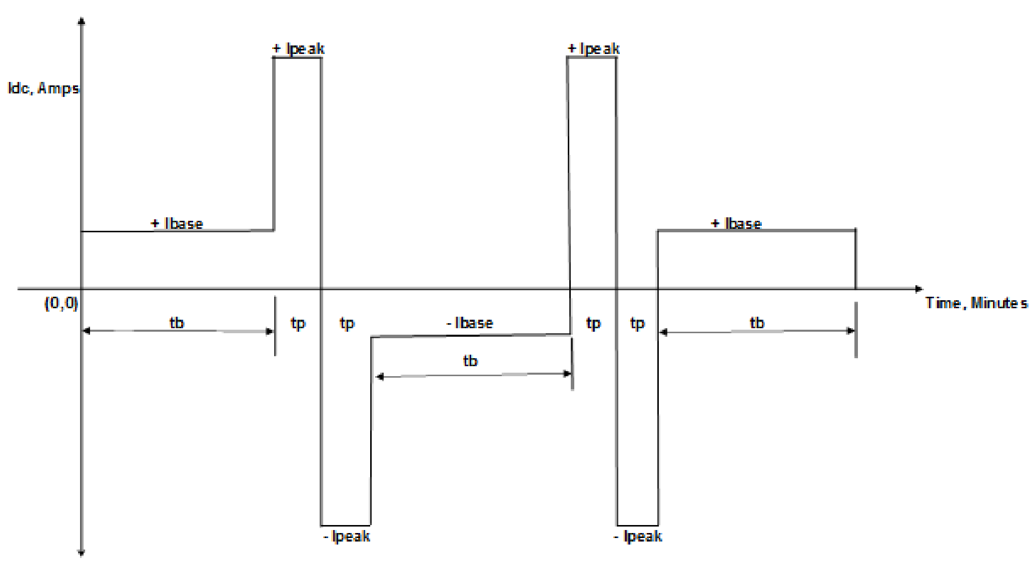
Recommendation

We recommend that the NERC document suggest using the Standard GIC signature, proposed in the upcoming IEEE Std. PC57.163 GIC Guide, shown below. This signature was based on observation / study of a number of signatures of measured GIC currents on a number of power transformers located in different areas of the country. It was recognized that GIC current signatures can be generally characterized by a large number of consecutive narrow pulses of low – to – medium levels over a period of hours interrupted by high peaks of less than a minute, to several minutes, duration. Therefore, GIC signatures are made of two main stages of GIC; namely:

- Base Stage: Consists of multiples of small – to – moderate magnitudes of GIC current sustained for periods that could be as short as a fraction of an hour to several hours.
- Peak GIC Pulse Stage: Consists of high levels of GIC pulses of durations of a fraction of a minute to several minutes.

Utilities would provide values of the Base GIC (I_{base}) current and the Peak GIC current pulses (I_{peak}) specific to their power transformers on their respective power system. These two parameters are to be determined based on the geographic location of the transformer as well as the part of the power grid the transformer belongs to. For standardization purposes, the time durations of the base GIC and GIC pulses; t_b and t_p, respectively, can be fixed at 20 minutes and 3 minutes; respectively. Also, the full duration of the high level GMD event can be standardized to be 2 or 3 hours long; encompassing several cycles of the GIC signature. These parameters can be as conservative as they need to be.

Specifying a Standard GIC signature for the thermal Assessment of the thousands of power Transformers covered by the NERC document would allow using generic / simplified (but sufficiently accurate) thermal models for the thermal Assessment and, hence, a significantly less effort. On the other hand, the thermal Assessment of transformers, to be done correctly, for different more complex GIC signatures, would require much more time to complete.



Submitted by:

Mr. Raj Ahuja, Waukesha
Mr. Mohamed Diaby, Efacec
Mr. Johannes Raith, Siemens
Mr. Sanjay Patel, Smit
Dr. Ramsis Girgis, ABB

Exhibit I

Summary of Development History and Complete Record of Development

Notice of Request to Waive the Standard Process

Project 2013-03 – Geomagnetic Disturbance Mitigation

As required by Section 16 of the NERC Standard Processes Manual (SPM), this is official notice to stakeholders that the leadership of the Project 2013-03 Geomagnetic Disturbance Mitigation (GMD) Standards Drafting Team, the Project Management and Oversight Subcommittee liaison, the Standards Committee (SC) chair, and NERC Standards staff (Requesters) are requesting that the SC consider a waiver of the SPM. The Requesters ask to shorten the next formal comment and ballot period for draft standard TPL-007-1, and any subsequent formal comment and ballot periods prior to final ballot for that standard, from forty-five days to twenty-five days, with a ballot and non-binding poll during the last seven days of the twenty-five day period, and to shorten the final ballot for TPL-007-1 from ten days to seven days, in order to meet a Federal Energy Regulatory Commission (FERC) regulatory deadline. Section 16 of the SPM provides for the granting of a waiver for a regulatory deadline.

The SC will meet via teleconference to consider this waiver on its regularly scheduled Wednesday, October 22, 2014 call (to comply with the five business days' notice required by Section 16 of the SPM, this notice and its accompanying one-pager were submitted to the SC on October 15, 2014). The SC's teleconference will be noticed through an announcement and posted on the NERC website. Additional details about the waiver request are included below, and should a waiver be granted by the SC, it will be posted on the project page.

Justification for Current Waiver Request

In Order No. 779, the Commission directed the development of Reliability Standards to address GMDs in two stages.[1] In the first stage, NERC submitted Reliability Standard EOP-010-1, requiring owners and operators of the Bulk-Power System (BPS) to develop and implement Operating Procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. The second stage of Reliability Standards to address GMDs, the subject of this waiver request, requires NERC to develop proposed Reliability Standards that require owners and operators of the BPS to conduct initial and ongoing vulnerability assessments of the potential impact of benchmark GMD events on BPS equipment and the BPS as a whole.

FERC directed the submission of the stage two Reliability Standard within 18 months of the effective date of the final rule, *i.e.*, **January 21, 2015**.

TPL-007-1 has been posted for one 30-day informal comment period and two 45-day comment periods and ballots, receiving approval ratings of 55.77% and 57.95%, respectively.

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[1] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013)("Order No. 779").

The shortened comment period and ballot for TPL-007-1 serves several important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TPL-007-1, the shortened comment period will allow for one additional comment period and ballot, while still allowing the standard to be filed with the Commission by the January 21, 2015 deadline. This will also enable the drafting team to conduct additional outreach prior to the start of the ballot which may be important to ensure stakeholder support. Shortening the ballot period from ten days to seven days also provides scheduling flexibility that may be required to achieve the necessary milestones including scheduling a special call for NERC Board of Trustees adoption, while still allowing NERC and the industry to successfully meet the filing deadline.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Mark Olson,
Standards Developer, at mark.olson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Waiver Authorization for Project 2013-03 Geomagnetic Disturbance Mitigation

Action

Authorize a waiver of the Standard Process Manual (SPM) to:

a) Shorten the next additional formal comment period (and any subsequent additional formal comment periods) for draft standard TPL-007-1—Transmission System Planned Performance for Geomagnetic Disturbance (GMD) Events from forty-five days to twenty-five days, with a ballot and non-binding poll during the last seven days of the twenty-five day period; and

b) Shorten the final ballot period from ten days to seven days.

Background

The leadership of the GMD drafting team, NERC Staff, and the Project Management and Oversight Subcommittee liaison and Standards Committee (SC) chair have requested a waiver of the NERC Standards Processes Manual (SPM) as described in the actions above. Section 16 of the SPM provides for the granting of waivers to meet a regulatory deadline. As required in Section 16, NERC provided stakeholders with five business days' notice of this waiver. If a waiver is authorized, NERC will post notice of the waiver and notify the NERC Board of Trustees (Board) Standards Oversight and Technology Committee.

In Order No. 779, the Federal Energy Regulatory Commission (FERC) directed the development of Reliability Standards to address GMDs in two stages.[1] In the first stage, NERC submitted Reliability Standard EOP-010-1, requiring owners and operators of the Bulk-Power System (BPS) to develop and implement Operating Procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. In the second stage, which is the subject of this waiver request, NERC is developing a proposed Reliability Standard that requires owners and operators of the BPS to conduct initial and ongoing vulnerability assessments of the potential impact of benchmark GMD events on BPS equipment and the BPS as a whole.

FERC directed the submission of the stage two Reliability Standard within 18 months of the effective date of the final rule, *i.e.*, **January 21, 2015**.

TPL-007-1 has been posted for one 30-day informal comment period and two 45-day comment periods and ballots, receiving approval ratings of 55.77% and 57.95%, respectively.

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The shortened comment period and ballot for TPL-007-1 serves several important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TPL-007-1, the shortened comment period will allow for one additional comment period and ballot, while still allowing the standard to be filed with FERC by the January 21, 2015 deadline. This will also enable the drafting team to conduct additional outreach prior to the start of the ballot which may be important to ensure stakeholder support. Shortening the ballot period from ten days to seven days also provides scheduling flexibility that may be required to achieve the necessary milestones including scheduling a special call for NERC Board adoption, while still allowing NERC and the industry to successfully meet the filing deadline.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.
4. The second draft of the proposed Reliability Standard was posted for formal comment and additional ballot from August 27, 2014 through October 10, 2014.

Description of Current Draft

This is the third draft of the proposed Reliability Standard. It is posted for 25-day comment and additional ballot.

Anticipated Actions	Anticipated Date
25-day Formal Comment Period with Additional Ballot	November 2014
Final ballot	December 2014
BOT adoption	December 2014

Effective Dates

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale:

Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s), in accordance with Requirement R1.

Rationale for Requirement R1:

In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformers due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1,

which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Rationale for Requirement R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

R4. Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the

requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Rationale for Requirement R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4 Part 4.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5 Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5 part 5.1.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6 Part 6.4 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall: *[Violation Risk Factor: High]* *[Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Rationale for Requirement R7:

Corrective Action Plans are defined in the NERC Glossary of Terms:

A list of actions and an associated timetable for implementation to remedy a specific problem.

Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7 Part 7.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the planning event.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \qquad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

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[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[2] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2) or Table 2, β is applied to the reference geoelectric field using equation (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[3] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

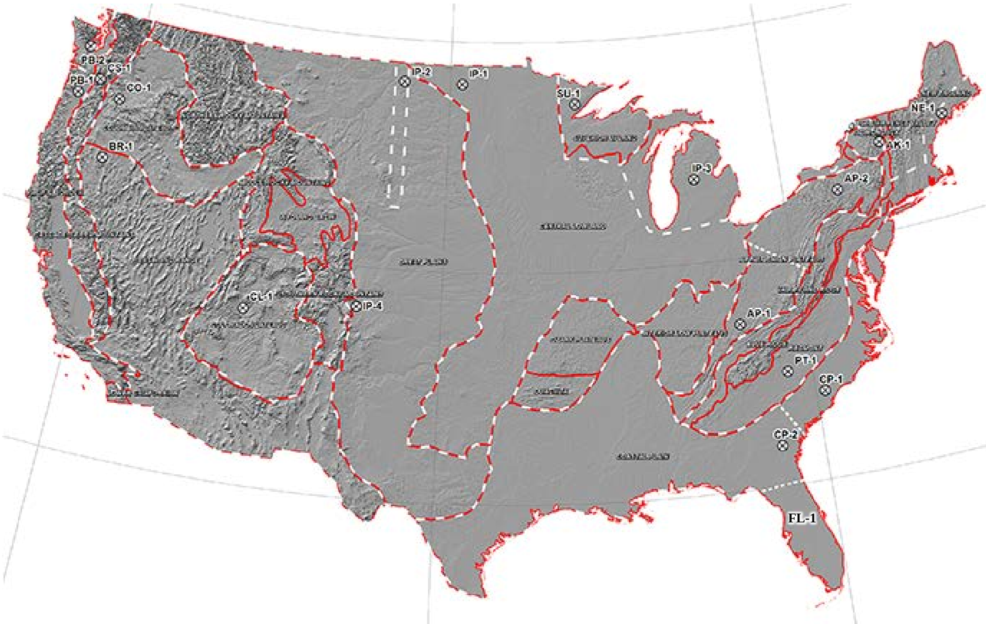

Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

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[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Rationale: Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]
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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

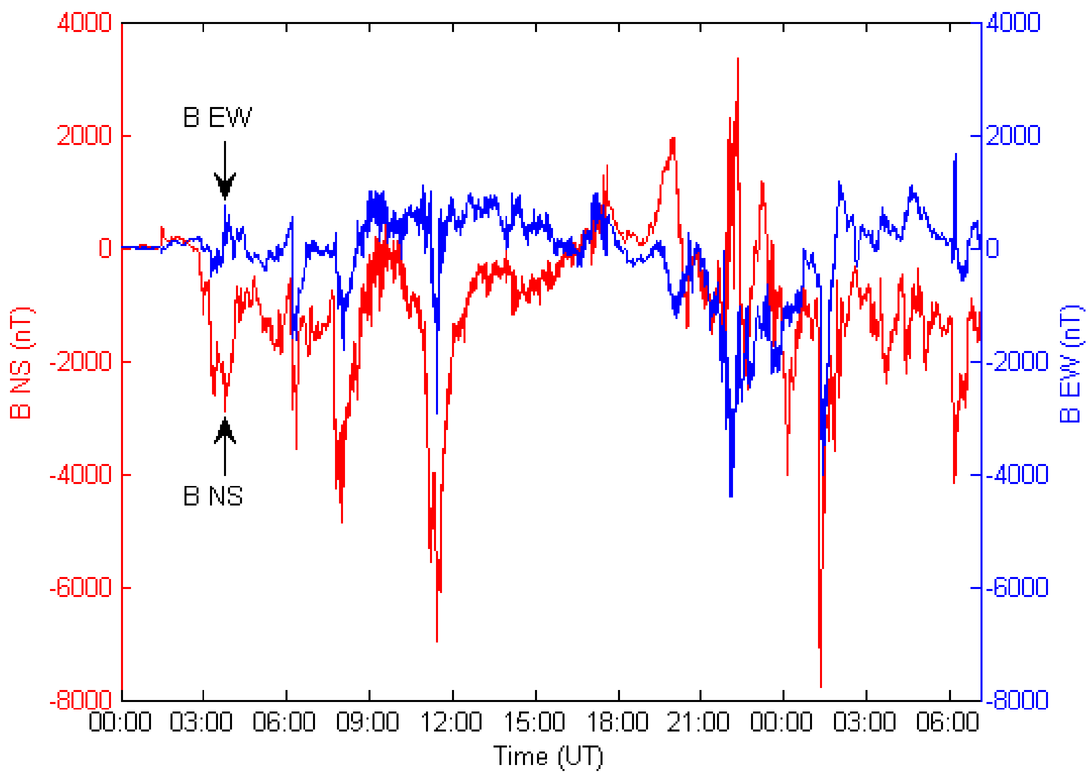


Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

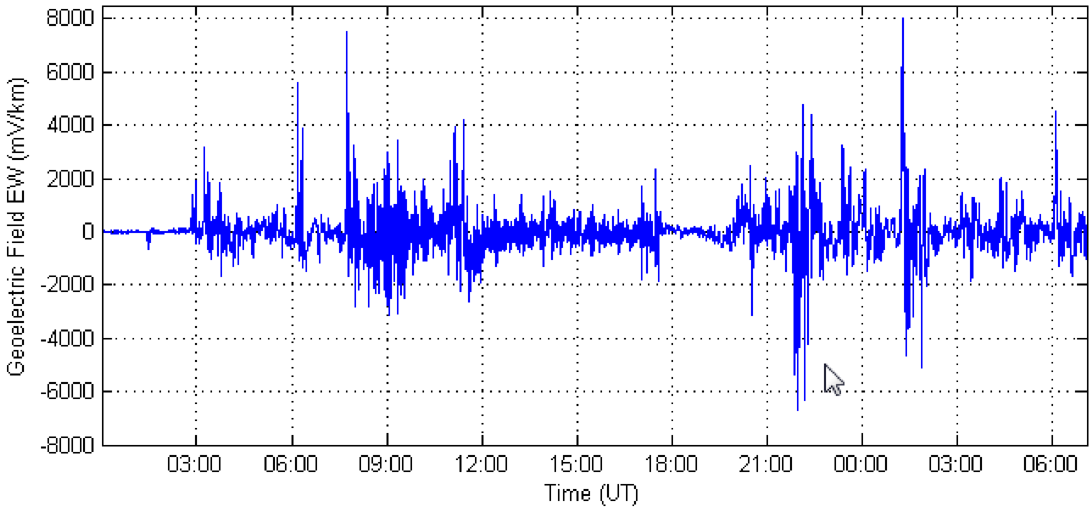


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

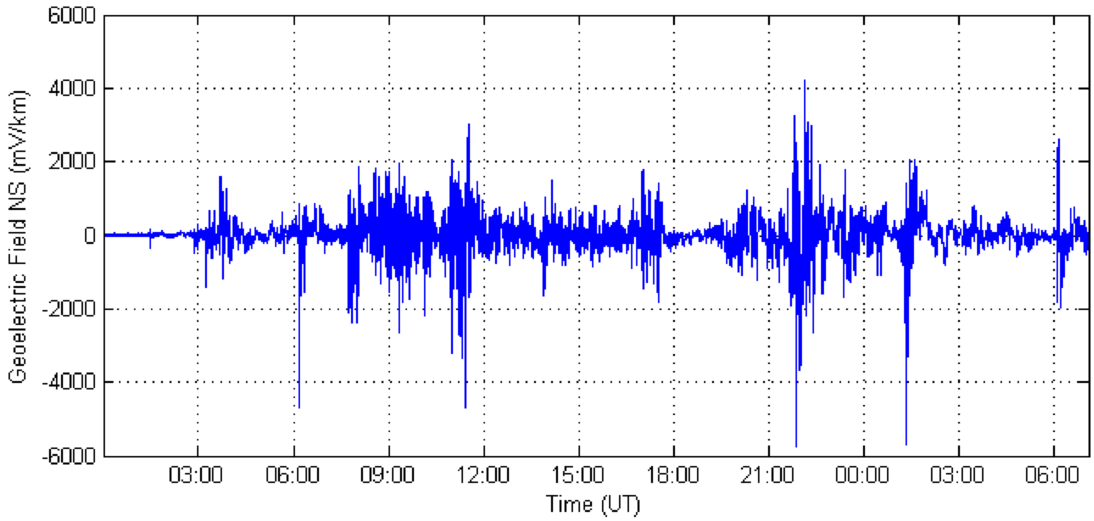


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

For Requirements R1, R2, R3, R5 and R6, each responsible entity shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

R5	Long-term Planning	Medium	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly

			power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of the required elements as listed in Requirement R6 Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include two of the required elements as listed in Requirement R6 Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include three of the required elements as listed in Requirement R6 Parts 6.1 through 6.3.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

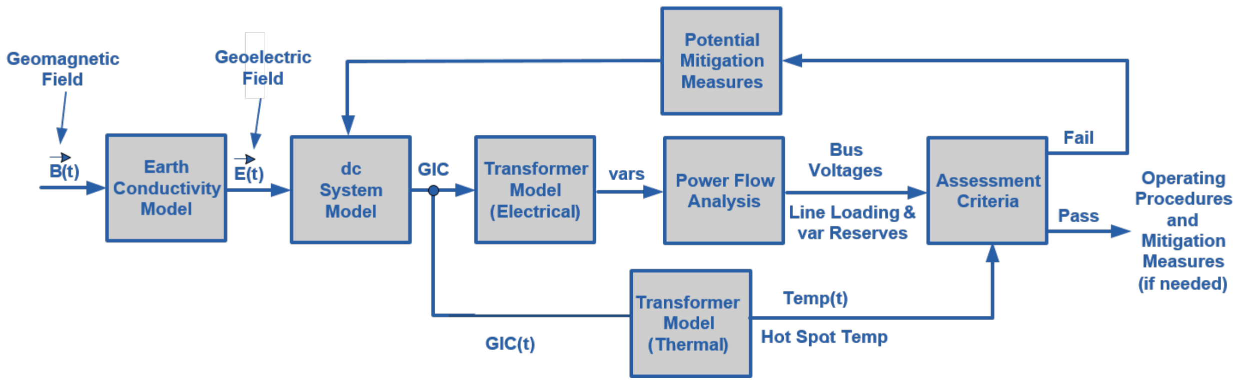
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.
4. The second draft of the proposed Reliability Standard was posted for formal comment and additional ballot from August 27, 2014 through October 10, 2014.

Description of Current Draft

This is the ~~second~~third draft of the proposed Reliability Standard. It is posted for ~~45~~25-day comment and additional ballot.

Anticipated Actions	Anticipated Date
~~45~~25-day Formal Comment Period with Additional Ballot	~~August~~November 2014
Final ballot	~~October~~December 2014
BOT adoption	~~Nov~~December 2014

Effective Dates

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**
2. **Number:** TPL-007-1
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

4.2. Facilities:

4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale:

Instrumentation transformers and station service transformers do not have significant impact on GIC flows; therefore, ~~they~~these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

5. **Background:**

During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation~~,~~(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with ~~each of~~ its Transmission ~~Planners,~~Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and ~~each of the~~ Transmission ~~Planners~~Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with ~~each of~~ its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s~~)~~), in accordance with Requirement R1.

Rationale for Requirement R1:

In some areas, planning entities may determine that the most effective approach to conducting a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

R2. ~~Responsible entities~~ Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s*)*. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Long-term Planning]*

M2. ~~A~~Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model ~~are~~is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformers due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages~~, for example~~.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

R3. ~~Responsible entities~~Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. ~~A~~Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Rationale for Requirement R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

R4. ~~Responsible entities~~ Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. ~~Studies~~The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. ~~Studies~~The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the ~~s~~System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning

Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1 If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. ~~A Responsible~~Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. ~~A~~Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of ~~its~~ completion to its Reliability Coordinator, adjacent Planning ~~Coordinators,~~Coordinator(s), adjacent Transmission ~~Planners,~~Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. ~~A~~Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Rationale for Requirement R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System ~~peak~~On-Peak Load and at least one System Off-~~p~~Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4 Part 4.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R5. ~~Responsible entities~~Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner ~~in the planning area~~ that owns an applicable Bulk Electric System (BES) power transformer~~.~~ in the planning area. The GIC flow information shall include~~ for each applicable power transformer~~: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. ~~Maximum~~The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1~~; and~~. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. ~~Effective~~The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 ~~for each~~in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer ~~where~~in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value ~~for the worst case geoelectric field orientation exceeds 15 A per phase~~in Part 5.1.

M5. ~~A~~Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC ~~flow information~~value to ~~each~~the Transmission Owner and Generator Owner that owns ~~an~~each applicable BES power transformer in the planning area as specified in Requirement R5 Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC ~~flows~~value provided in ~~p~~Part 5.1 ~~are~~is used ~~to screen the~~for transformer ~~fleet so that only those transformers that experience an effective GIC flow of 15A or greater are evaluated.~~thermal impact assessment.

~~The ~~GIC~~ flows~~(t) provided ~~by part~~in Part 5.2 ~~are~~is used to convert the steady-state GIC flows to time-series GIC data ~~used ~~for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5 part 5.1.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for ~~each of~~ its solely and jointly owned applicable ~~Bulk Electric System~~BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A per phase or greater ~~per phase~~. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its ~~applicable~~ solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A per phase or greater ~~per phase~~, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. ~~A process~~The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment ~~is~~are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6 Part 6.4 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R7. ~~Responsible entities~~Each responsible entity, as determined in Requirement ~~R1that conclude~~R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning ~~Coordinators,~~Coordinator(s), adjacent Transmission ~~Planners,~~Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. ~~A~~Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. ~~A~~Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning ~~Coordinators,~~Coordinator(s), adjacent Transmission ~~Planners, and any other~~Planner(s), a functional entity referenced in the Corrective Action Plan~~ or to~~, and any functional entity ~~who has submitted~~that submits a written request and has a reliability-related need, as specified in Requirement R7. ~~A~~Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Rationale for Requirement R7:

Corrective Action Plans are defined in the NERC Glossary of Terms:

> *A list of actions and an associated timetable for implementation to remedy a specific problem.*

Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7 Part 7.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Table 1 –Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\cancel{\alpha = 0.001 \cdot e^{(0.115 \cdot L)}} \alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[2] ~~;~~ or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2~~),~~) or Table 2, β is applied to the reference geoelectric field using equation (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[3] ~~.~~ The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

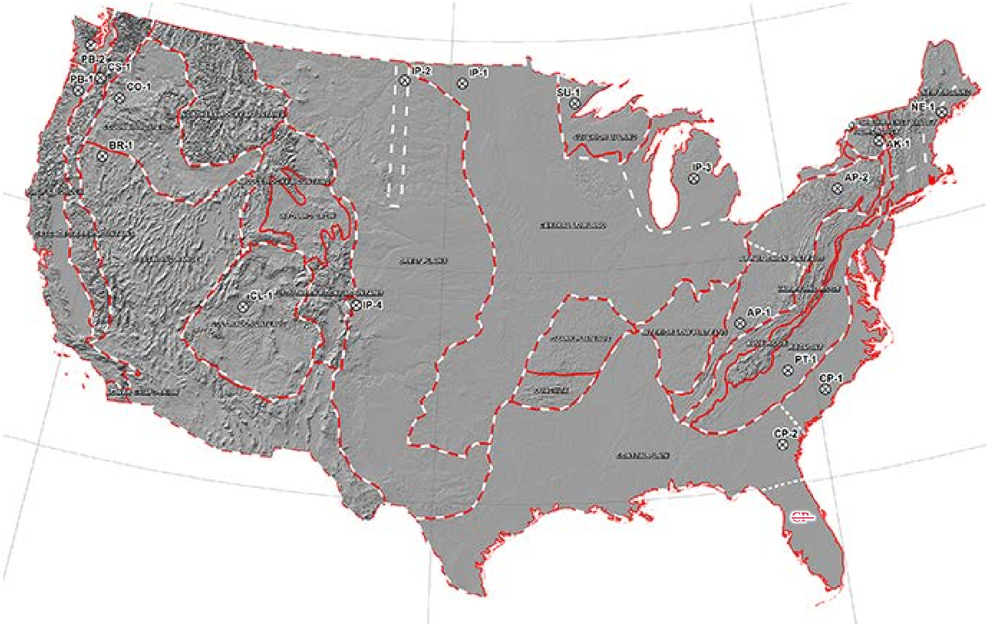


Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

4 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
~~CP3~~FL1	0.~~94~~74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Rationale: Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures~~.~~ 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series whe~~re~~n a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

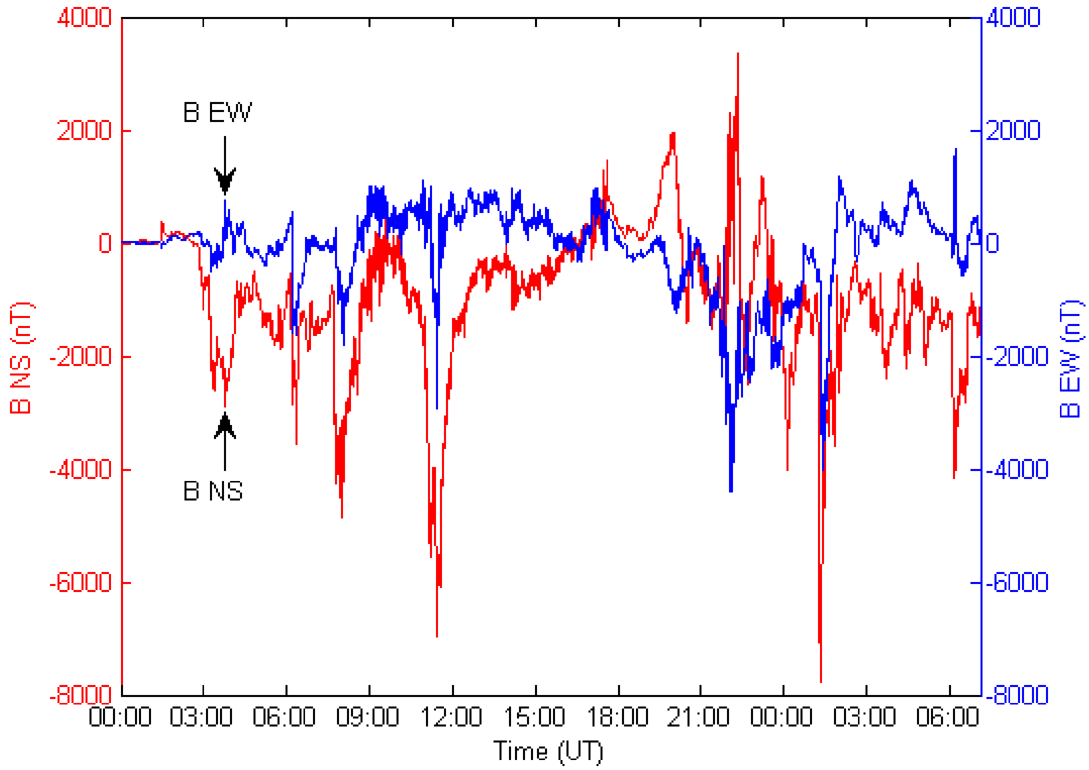


Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

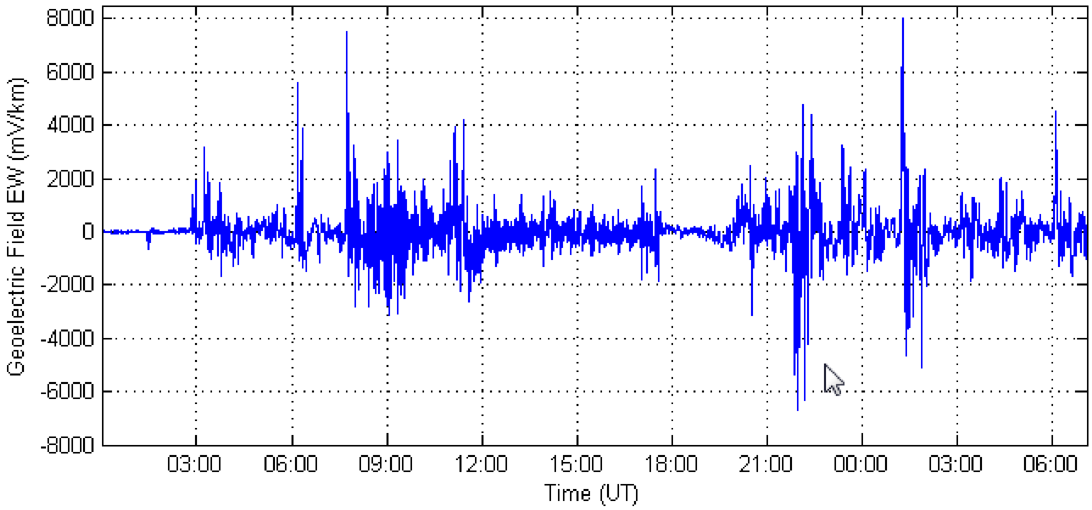


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

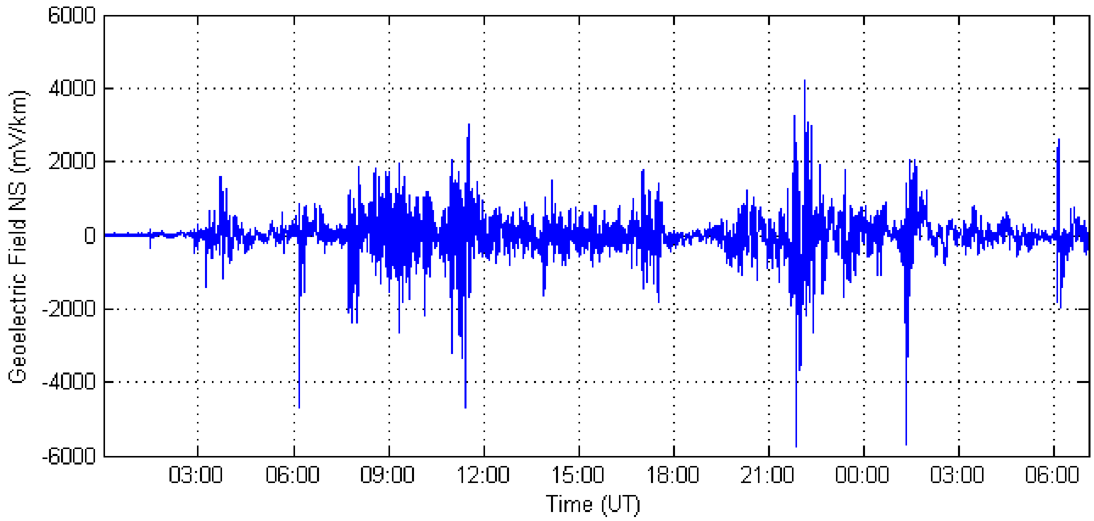


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

~~The~~For Requirements R1, R2, R3, R5 and R6, each responsible entit~~ies~~y shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant~~,~~ it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints ~~Text~~

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with ~~each of~~ its Transmission ~~Planners,~~Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and ~~each of the~~ Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	~~Medium~~High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

R5	Long-term Planning	Medium	~~N/A~~ The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	~~N/A~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity ~~failed to provide one of~~ provided the ~~elements listed~~effective GIC time series, GIC(t), in ~~Requirement R5 parts 5.1 to 5.2 to each Transmission Owner and Generator Owner in the planning area that owns an applicable power transformer~~response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity ~~failed to~~did not provide ~~two of~~ the ~~elements listed in Requirement R5 parts 5.1 to 5.2 to each~~ maximum effective GIC value to the Transmission Owner and Generator Owner ~~in the planning area~~ that owns ~~an~~each applicable BES power transformer in the planning area; OR The responsible entity did not provide ~~GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner in~~ the ~~planning area that owns an applicable power transformer.~~effective GIC time series, GIC(t), upon written request.
R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned

			owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5~~;~~. ~~OR~~ ~~The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.4.~~	of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include ~~two~~one of the required elements as listed in	of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include ~~three~~two of the required elements as listed in	and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 ~~p~~Part 5.1 is ~~15~~75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include ~~four~~three of the required elements as listed in Requirement R6 ~~p~~Parts 6.1 through 6.~~4~~3.

				Requirement R6 ~~p~~Parts 6.1 through 6.~~4~~3.	Requirement R6 ~~p~~Parts 6.1 through 6.~~4~~3.	
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 ~~p~~Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 ~~p~~Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 ~~p~~Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

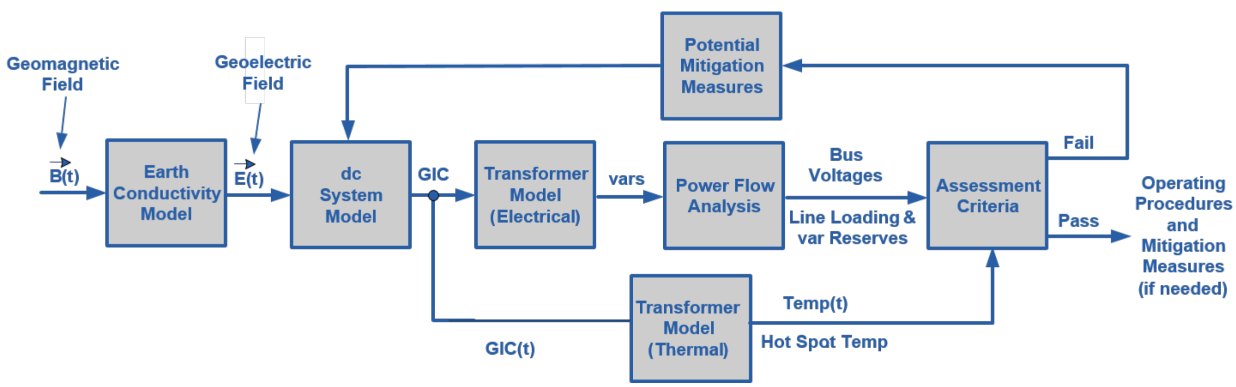
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC ~~time series~~ information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC ~~s~~System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in ~~p~~Part 5.1 is used ~~to screen the~~for transformer ~~fleet such that only~~thermal impact assessment. Only those transformers that experience an effective GIC ~~flow~~value of ~~15A~~75 A or greater ~~are evaluated~~per phase require evaluation in Requirement R6.

~~The effective GIC time series, GIC~~GIC(t~~),~~) provided in ~~p~~Part 5.2 is used to ~~conduct the~~ convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment ~~(see~~. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper ~~for details).~~.

The peak GIC value of ~~15 amps~~75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low. ~~Additional information is in the following section.~~

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. ~~A process~~Approaches for conducting the assessment ~~is~~are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the ~~maximum~~ effective GIC ~~in~~value for the transformer is less than ~~15 Amperes~~75 A per phase, as determined by a GIC analysis of the System. Justification for this ~~screening~~ criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding ~~the maximum effective GIC~~this value ~~provided in Requirement R5 Part 5.2~~ is also a justifiable threshold criteri~~a~~on that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required,

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

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None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
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Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **8 p.m. Eastern, November 21, 2014**.

If you have questions please contact Mark Olson or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages. Project 2013-03 responds to the FERC directives as follows:

- Stage 1. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June, 2014.
- Stage 2. Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the proposed standard will require the applicable entity to develop corrective actions to mitigate the risk of voltage collapse, uncontrolled separation, or Cascading. The Stage 2 standard must be filed with FERC by January 2015.

TPL-007-1 and supporting white papers were posted for formal comments from June 13 through July 30, 2014, and from August 27 through October 10, 2014. The standard drafting team (SDT) has made several revisions to the proposed standard and Transformer Thermal Impact Assessment white paper based on stakeholder input. There were no changes to the implementation plan.

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

Questions on Draft TPL-007-1

1. **Transformer thermal impact assessment**. The SDT has revised the Transformer Thermal Impact Assessmment white paper and Screening Criterion white paper with additional technical details. The screening criterion for transformer thermal assessments was increased from 15 A per phase to 75 A per phase. Additionally, look up tables provide a transformer thermal assessment approach based on available models. Do you agree with these changes? If not, please provide a specific recommendation and technical justification.

   ☐ Yes
   ☐ No

   Comments:

2. **TPL-007-1**. Do you agree with the changes made to TPL-007-1? If not, please provide technical justification for your disagreement and suggested language changes.

   ☐ Yes
   ☐ No

   Comments:

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
Draft: October 27, 2014

RELIABILITY | ACCOUNTABILITY



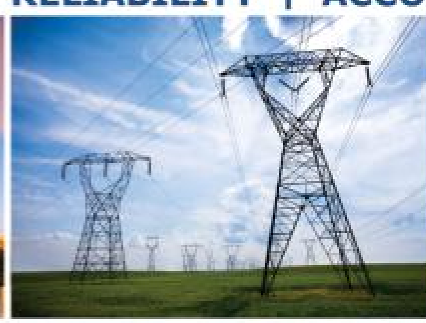
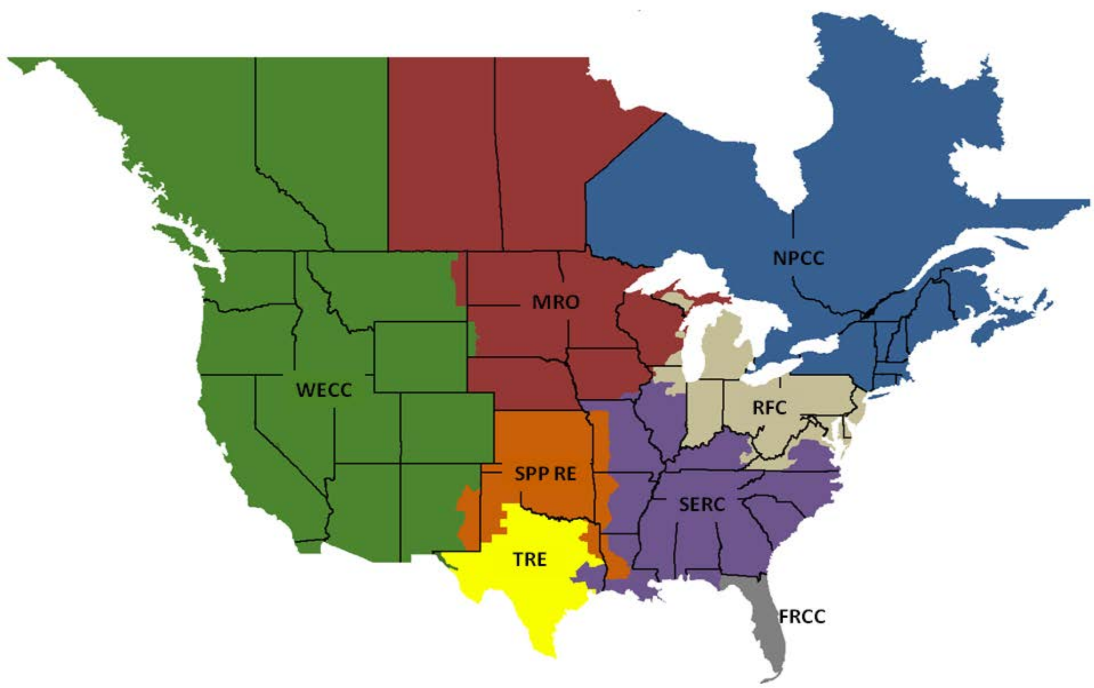



Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

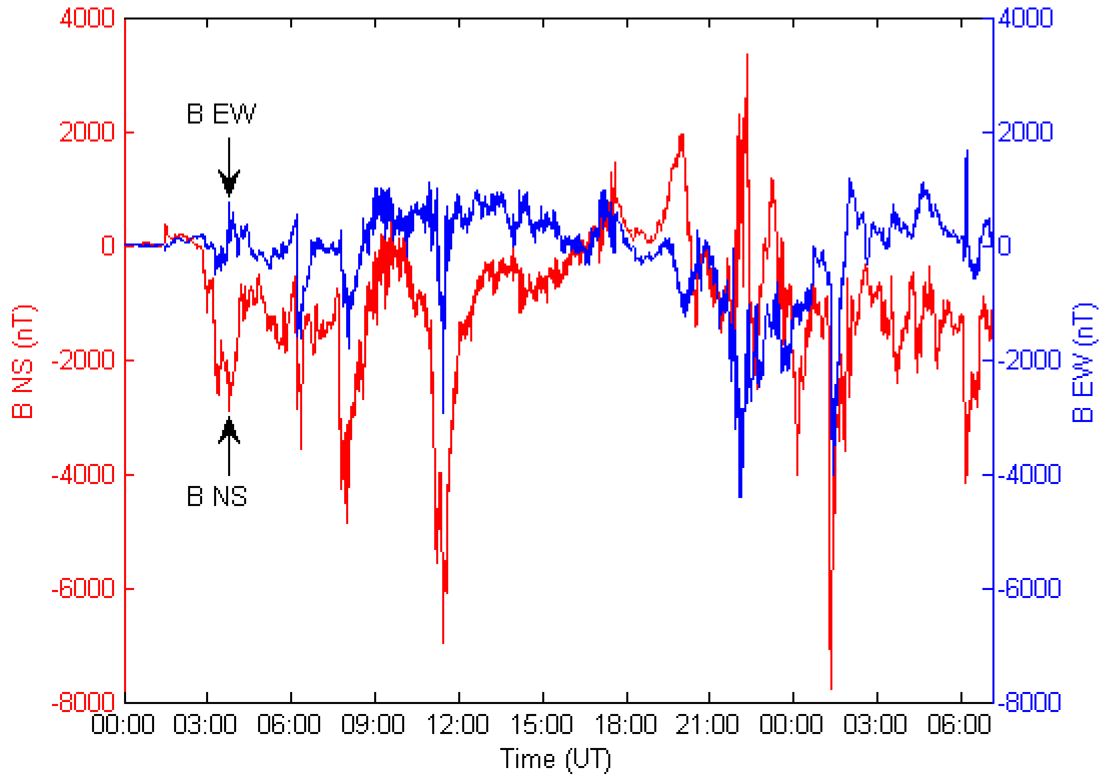


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

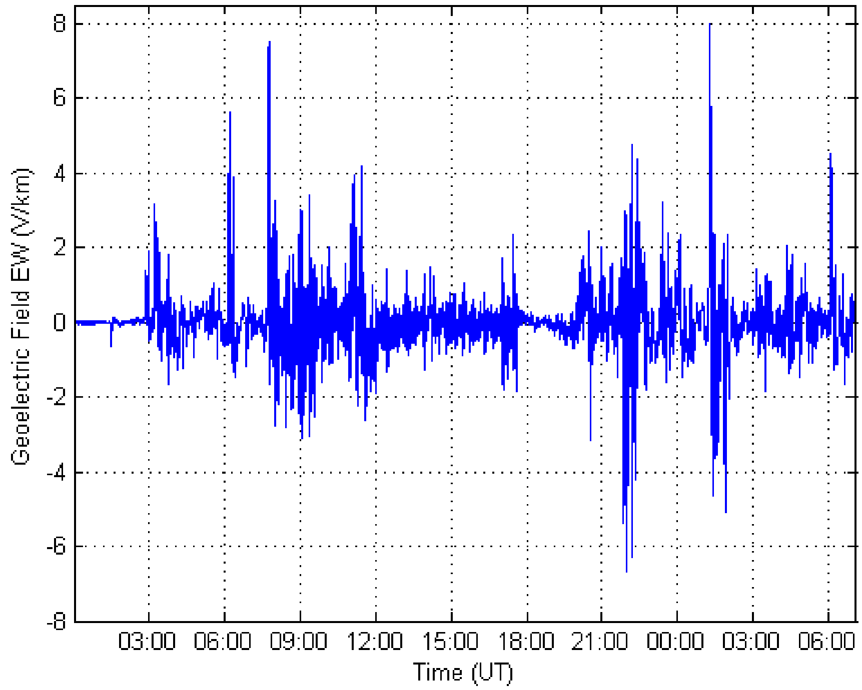


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

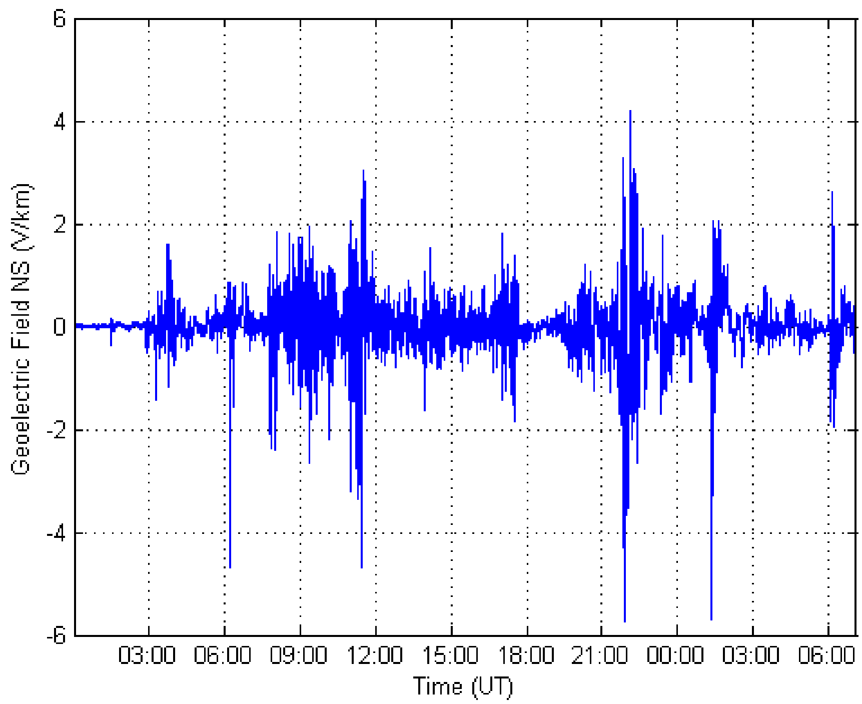


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

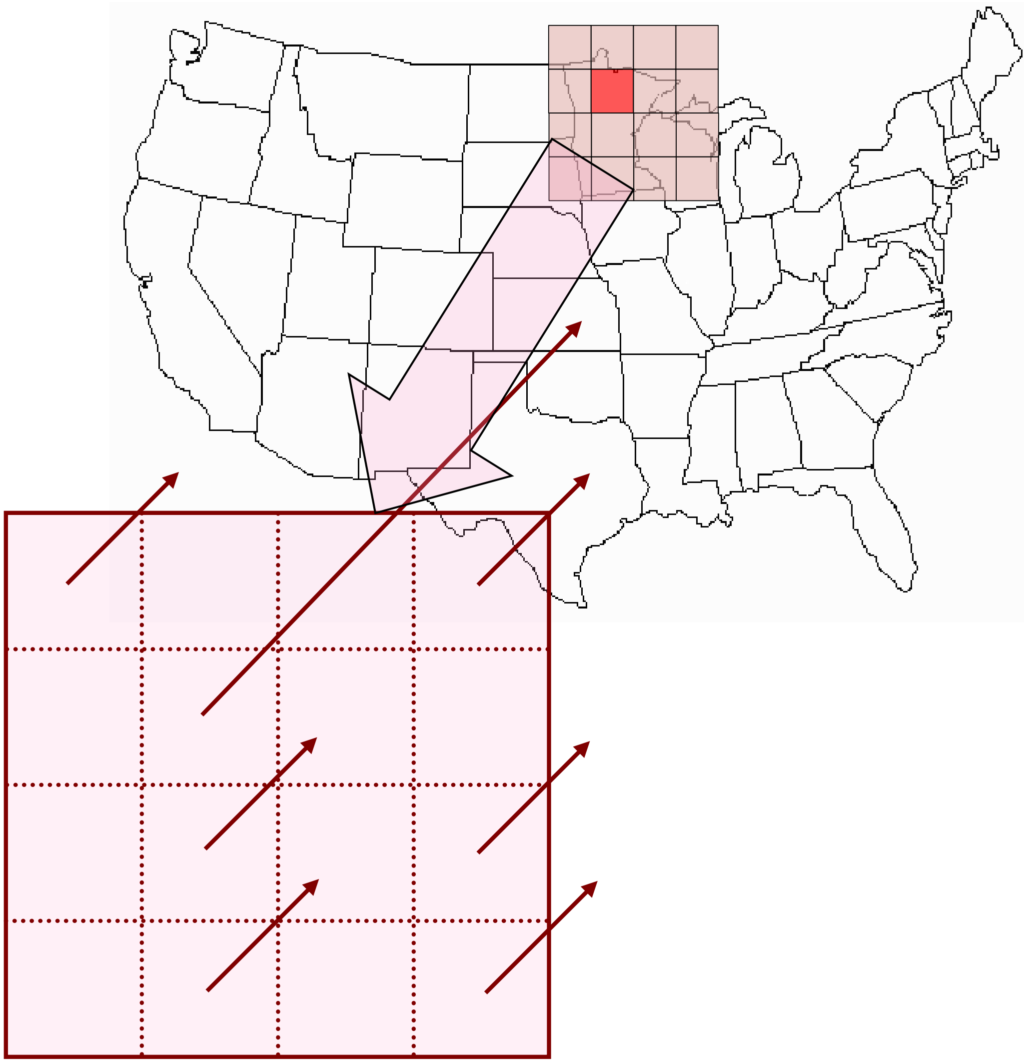


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

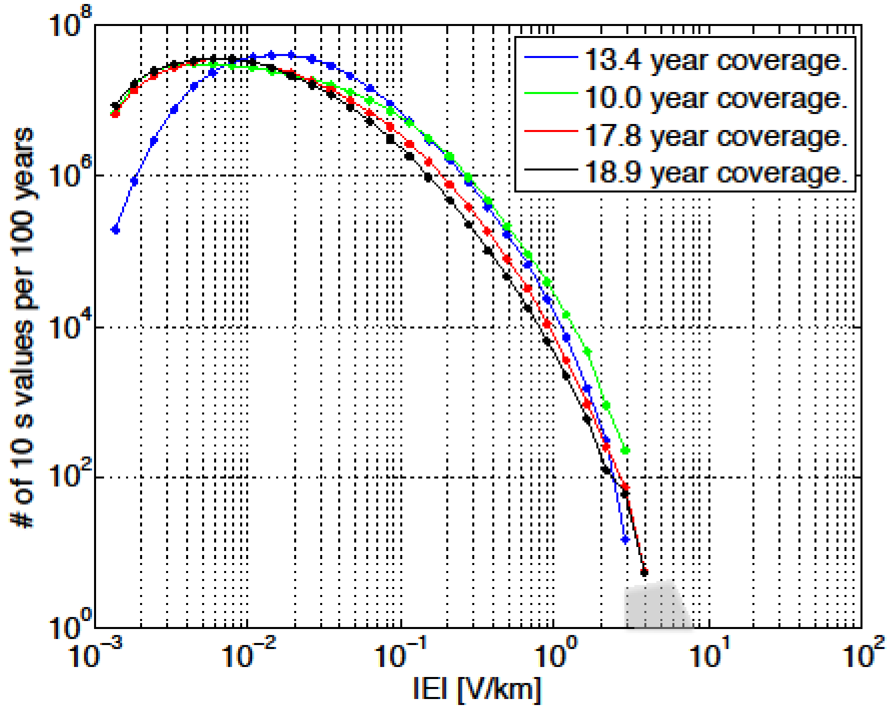


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

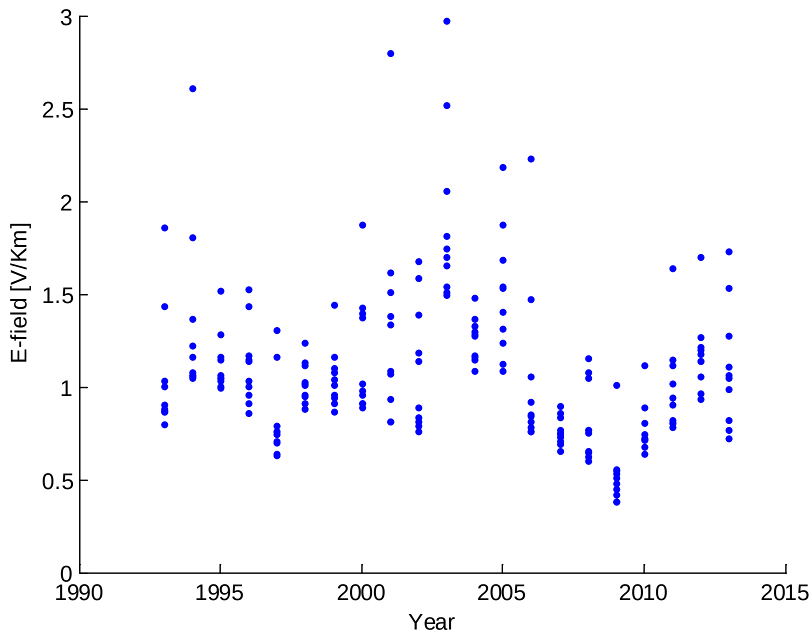


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

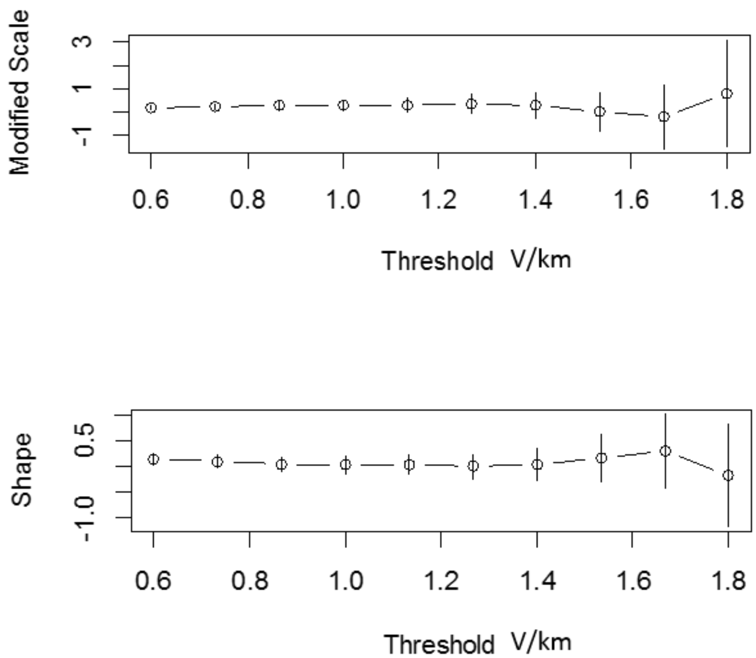


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

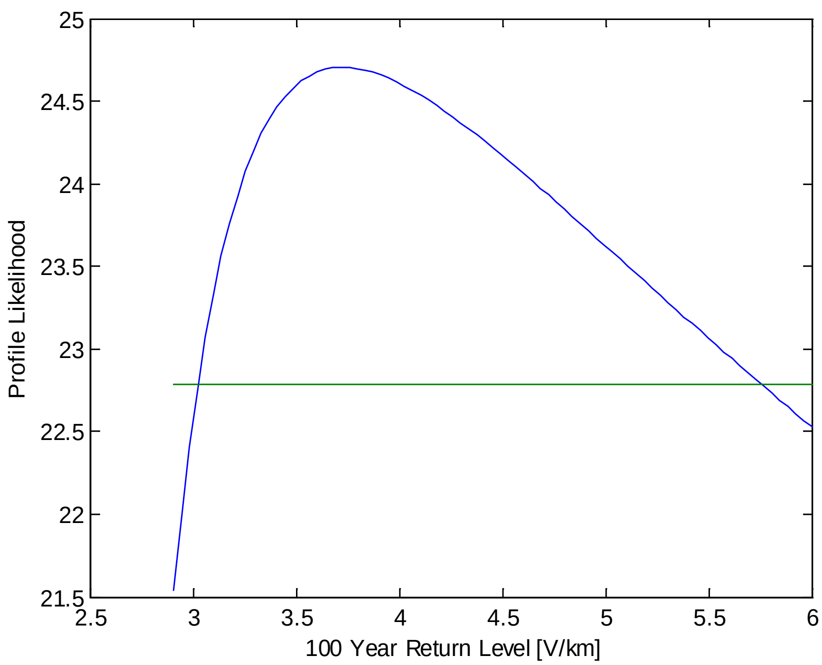


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

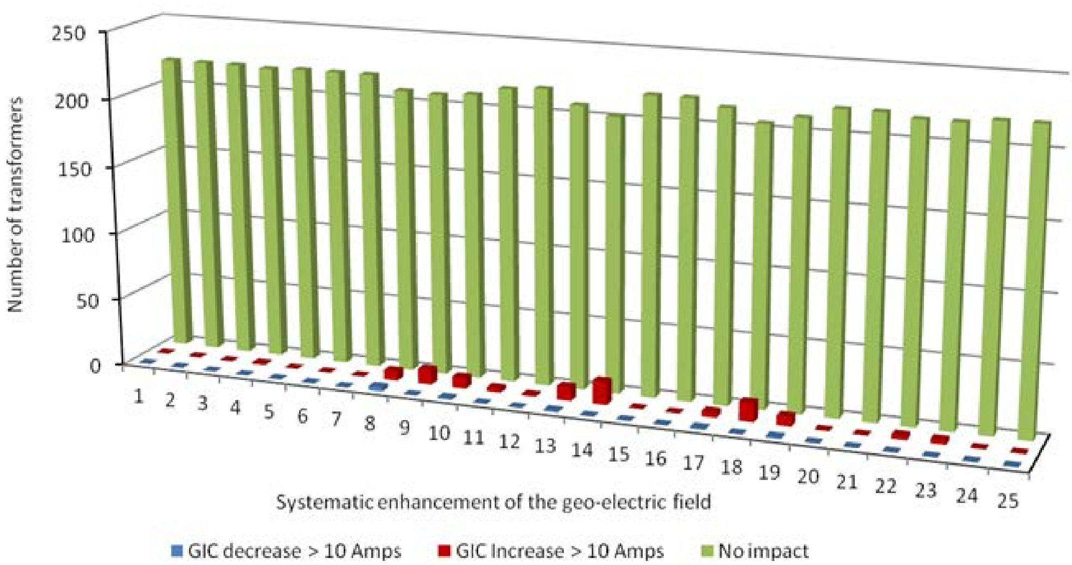


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

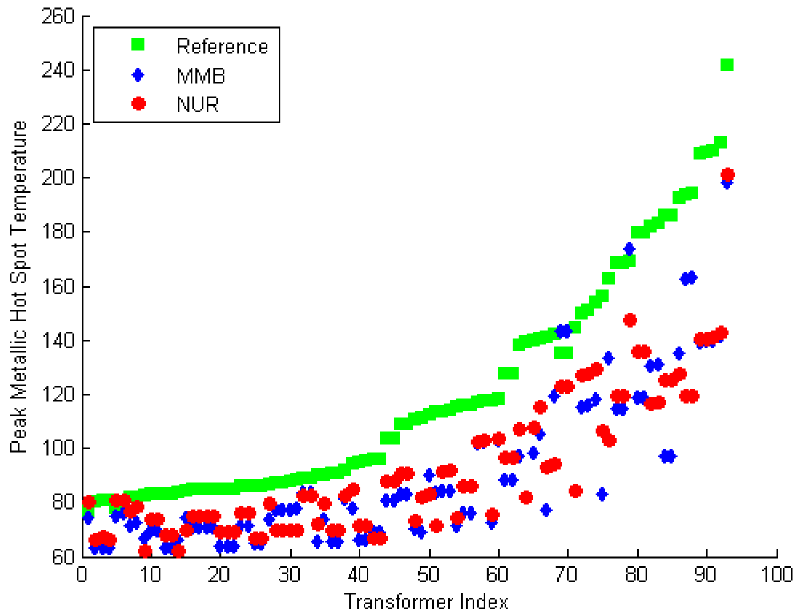


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

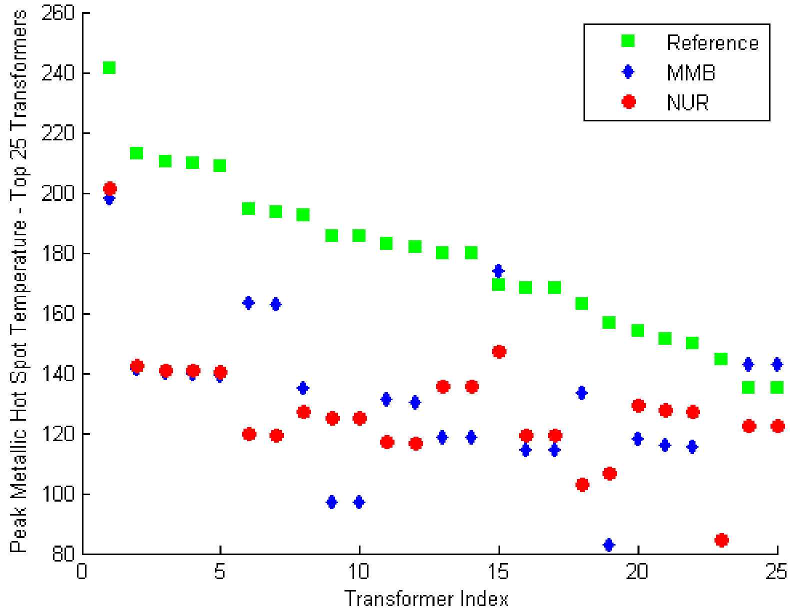


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

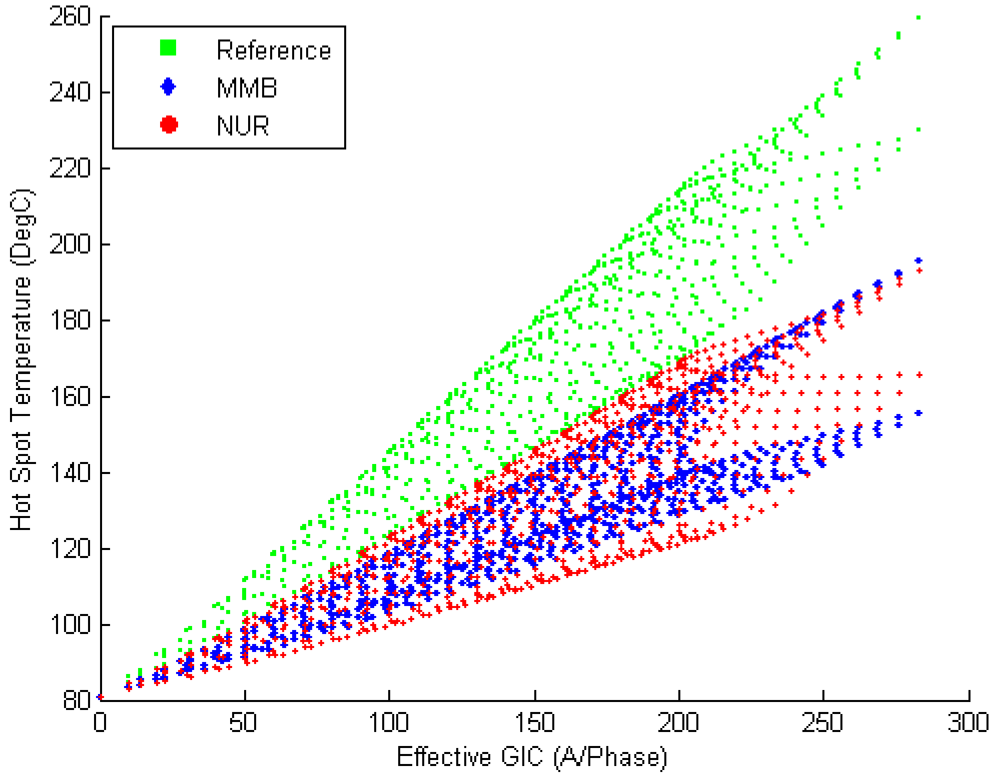


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

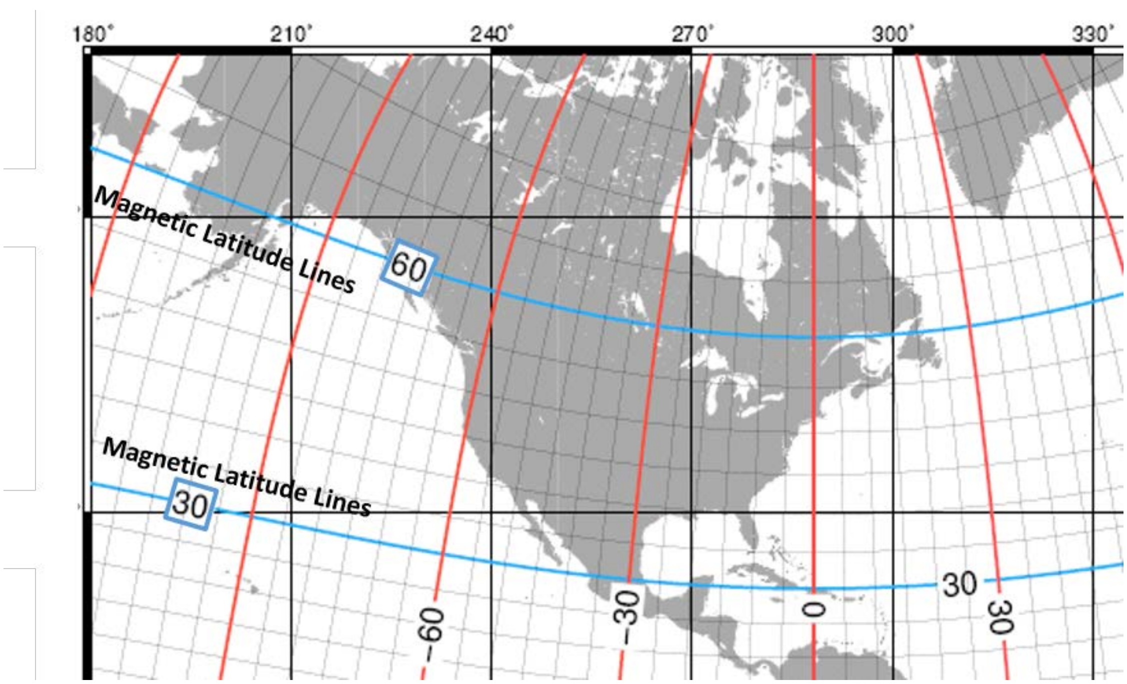


Figure II-1: Geomagnetic Latitude Lines in North America

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[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	**Scaling Factor1 (α)**
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$
\begin{aligned}
E_N &= (z(t)/\mu_o) * B_E(t) \\
E_E &= -(z(t)/\mu_o) * B_N(t) \\
E_{peak} &= \max\{|E_E(t), E_N(t)|\}
\end{aligned}
\tag{II.2}
$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

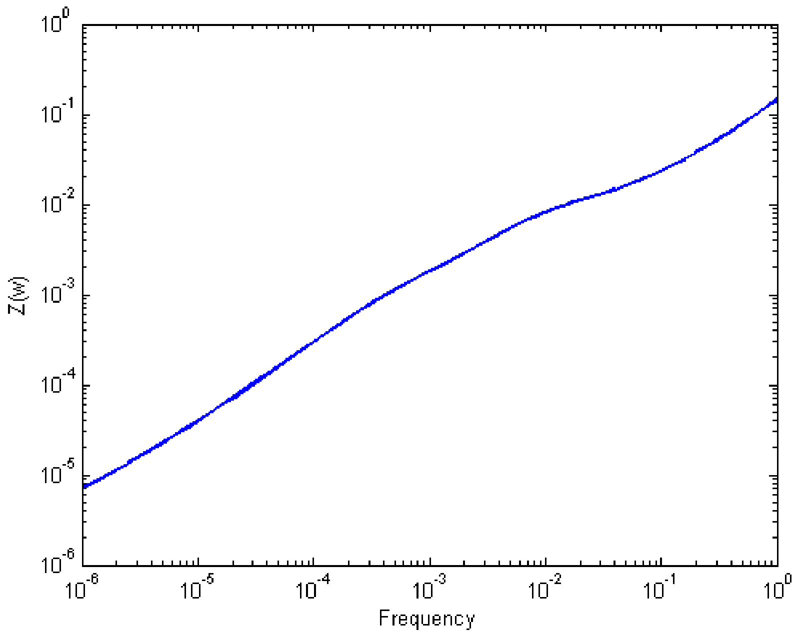


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

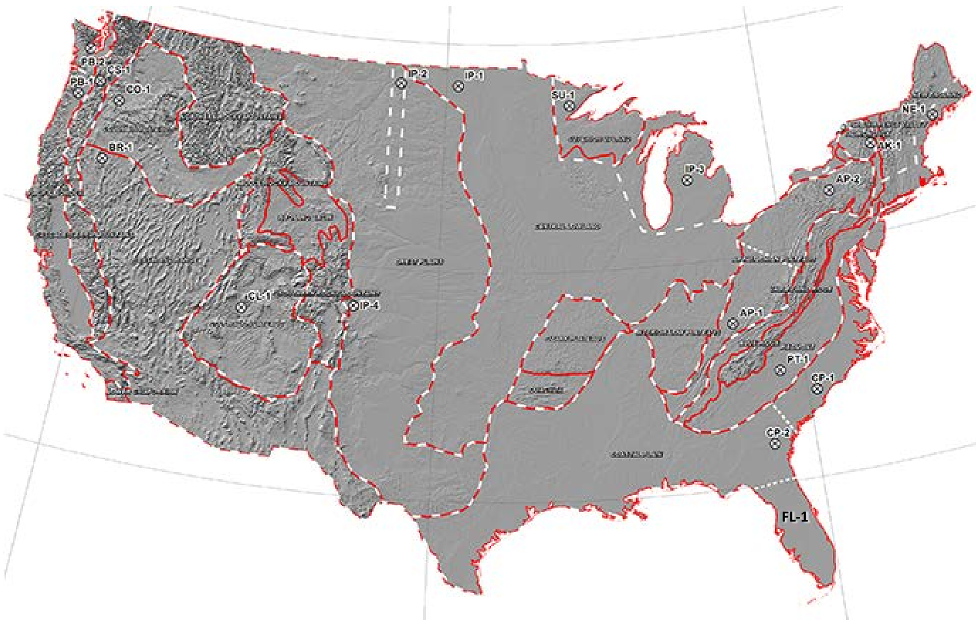
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use the largest β factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

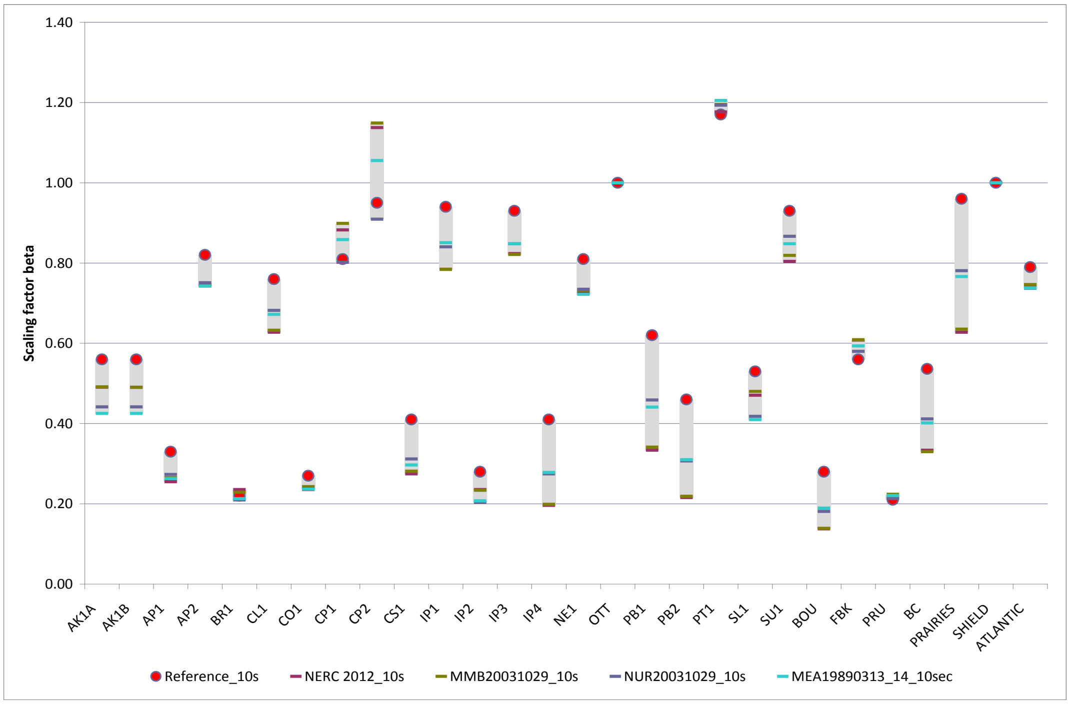


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2 V / km$$

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation Standard Drafting Team

Draft: ~~August~~ October ~~21~~27, 2014

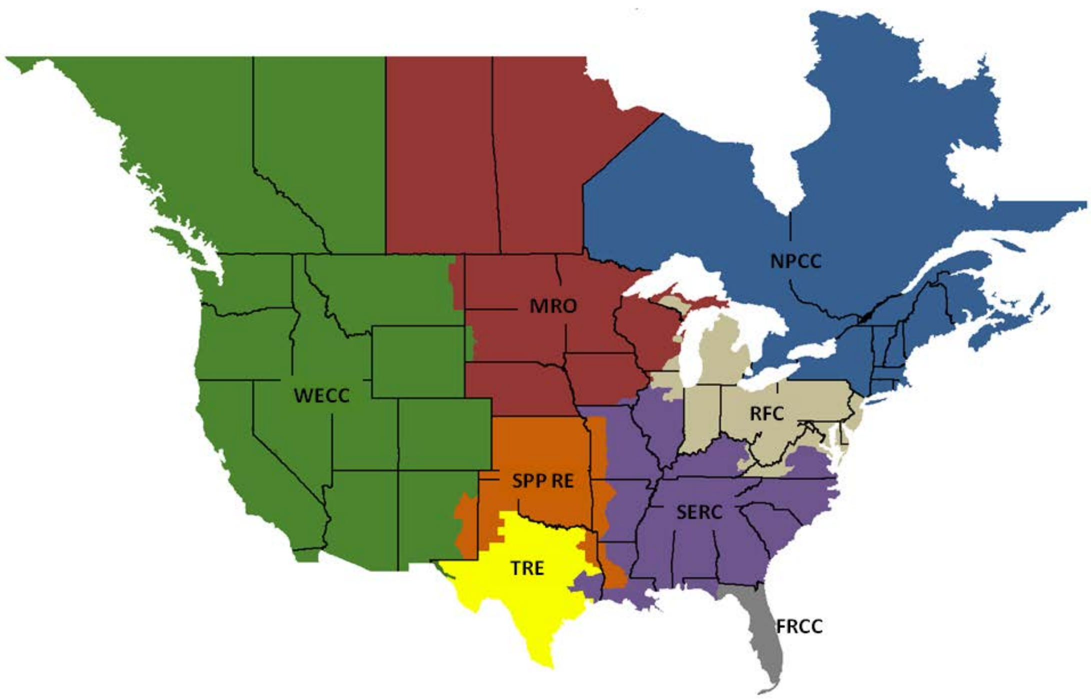
RELIABILITY | ACCOUNTABILITY

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

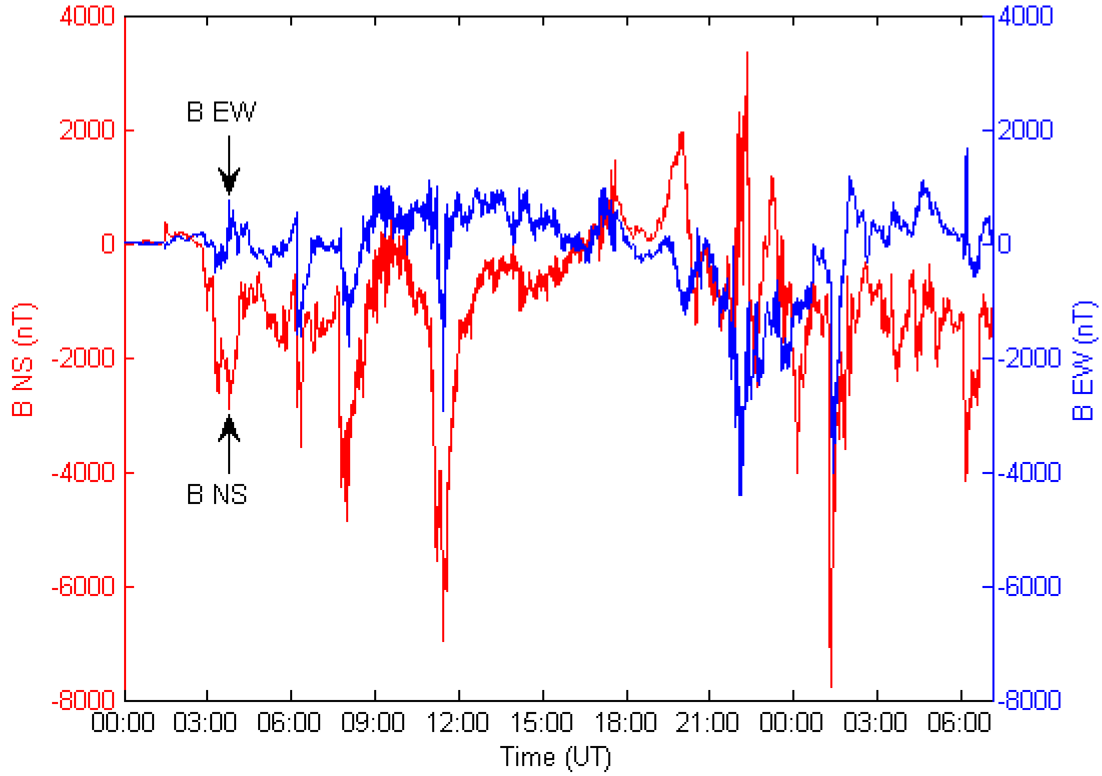


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

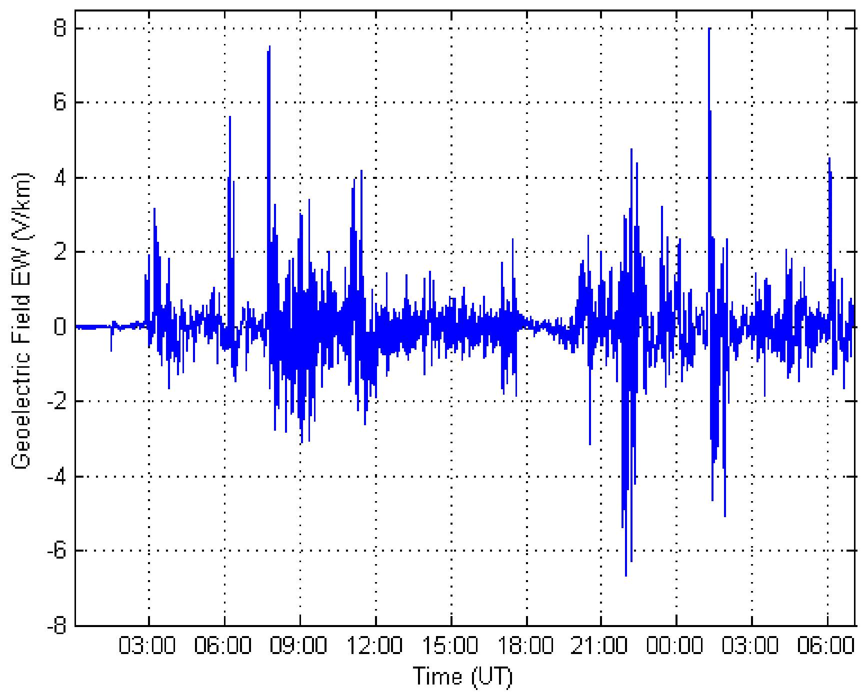


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

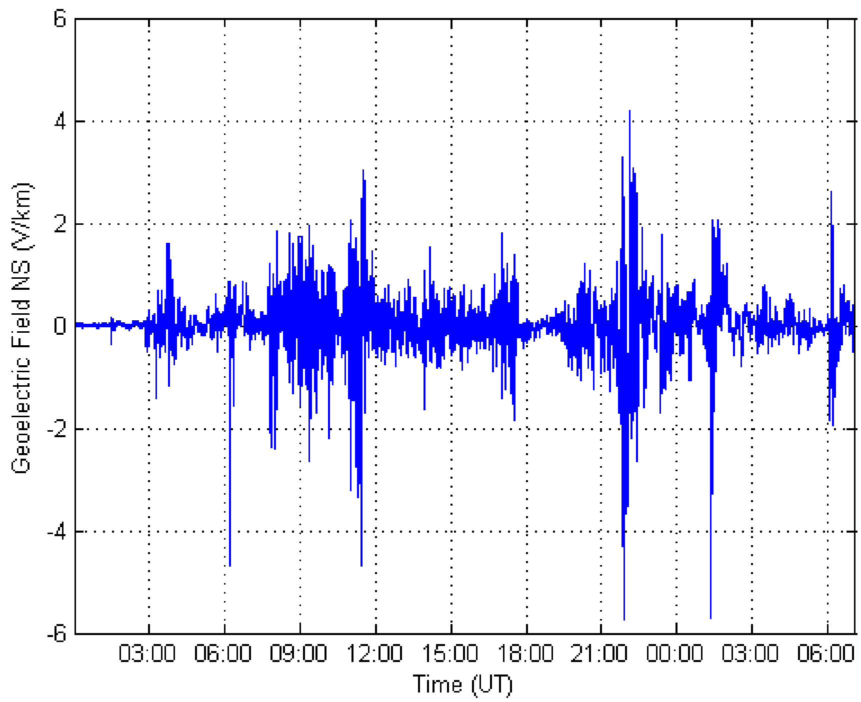


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

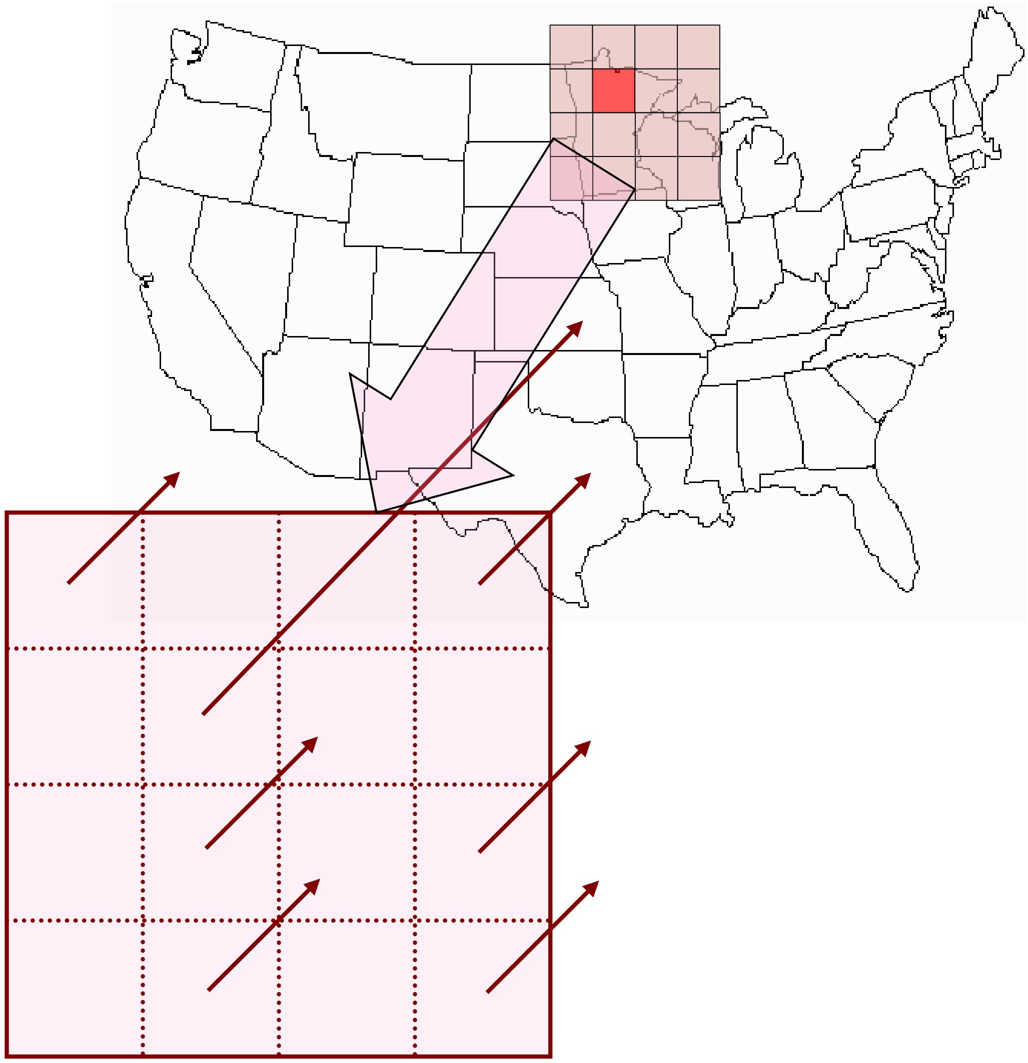


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

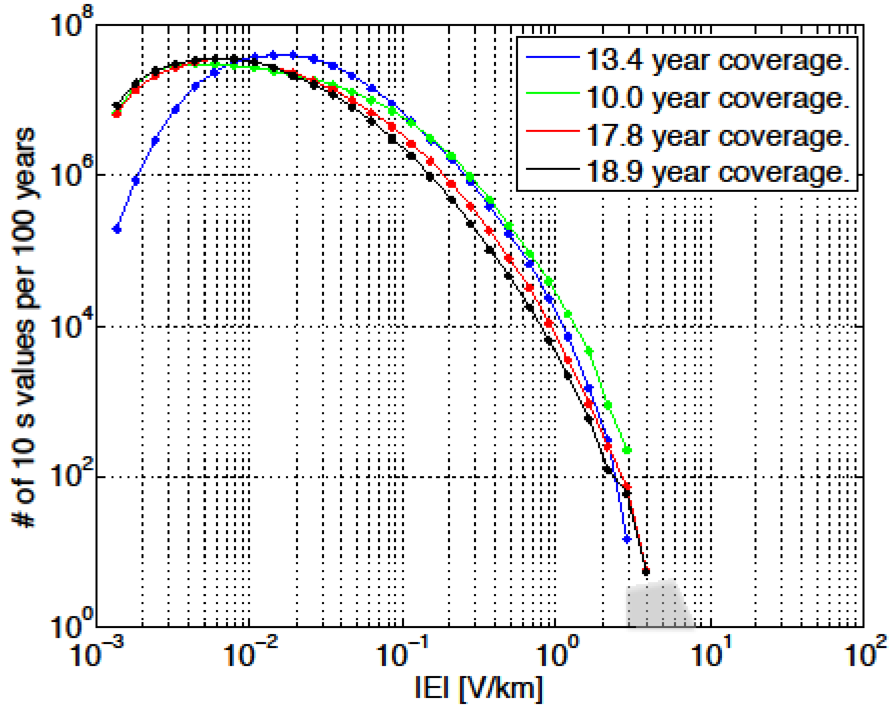


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

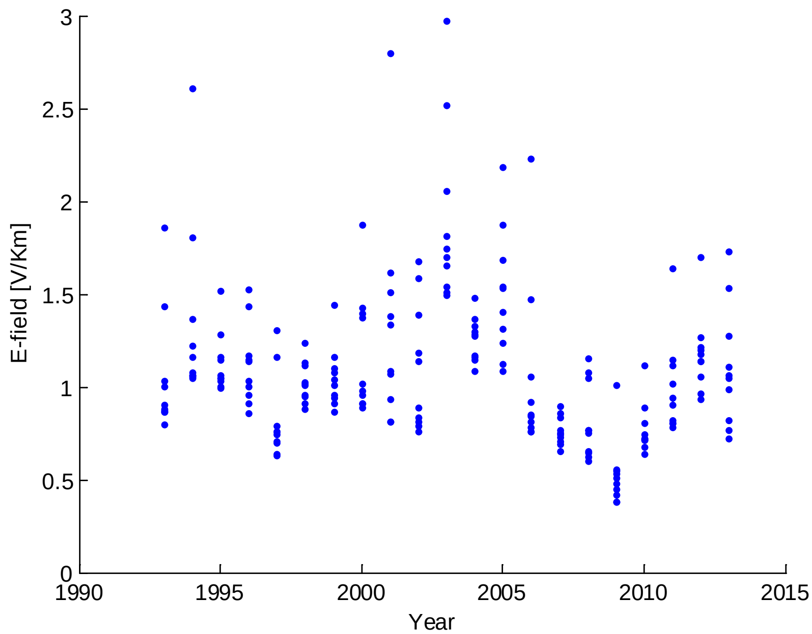


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

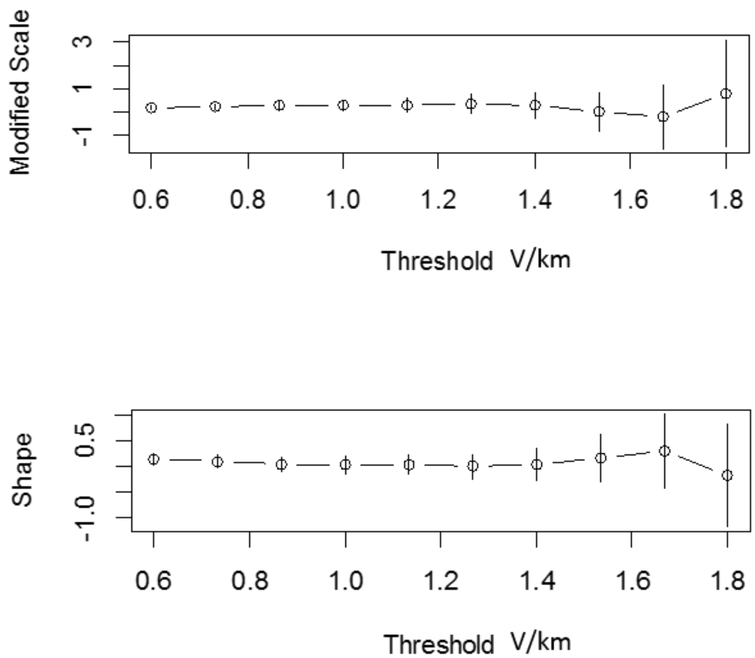


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

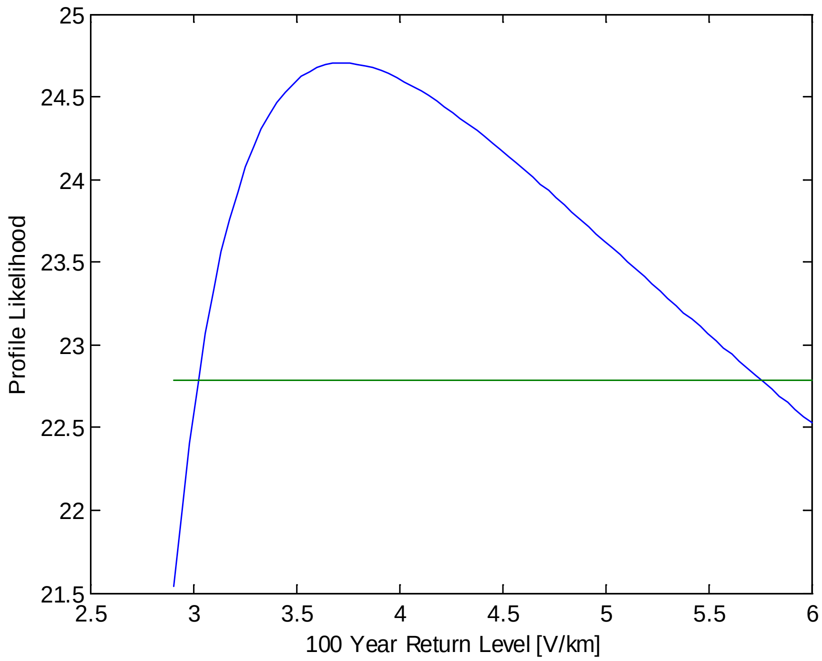


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

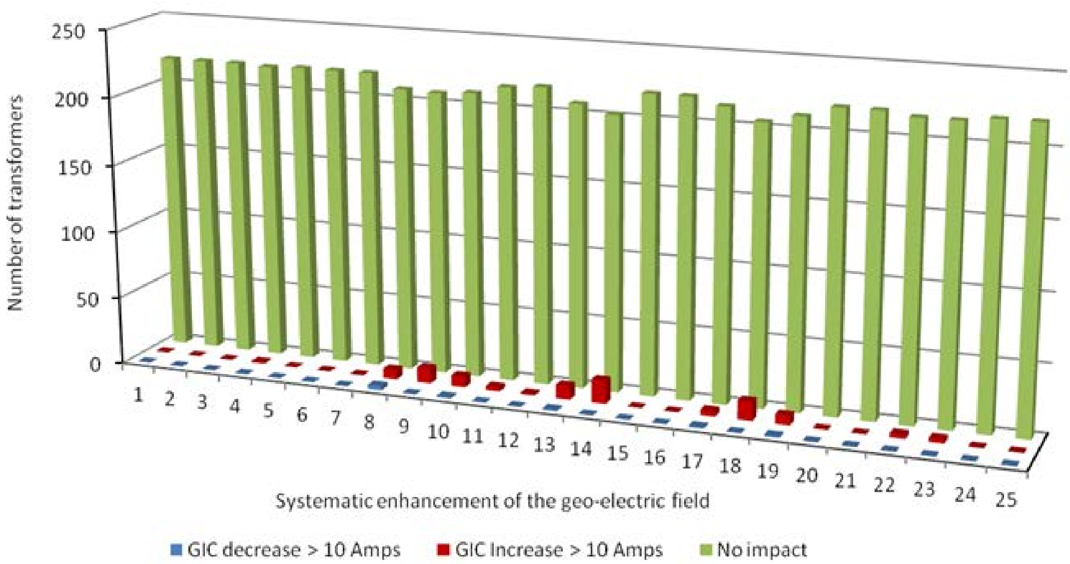


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar to **Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

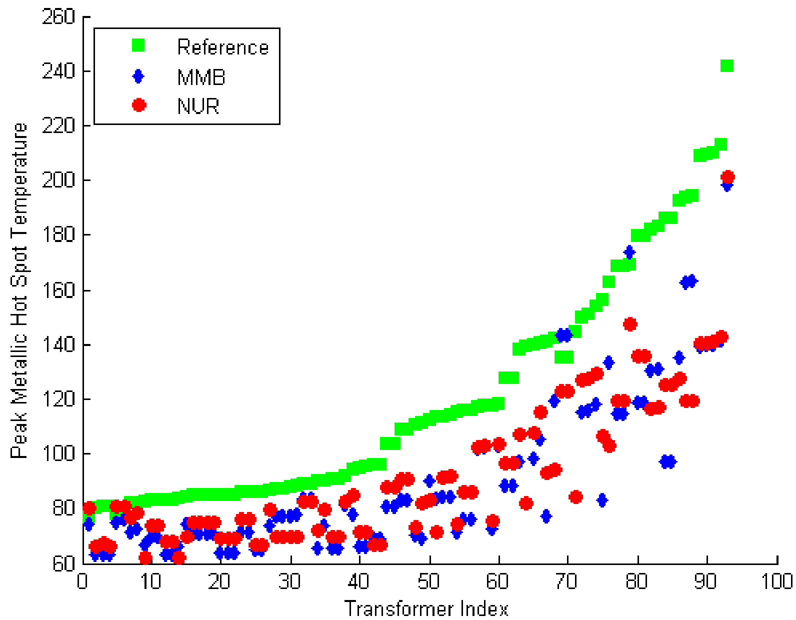


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

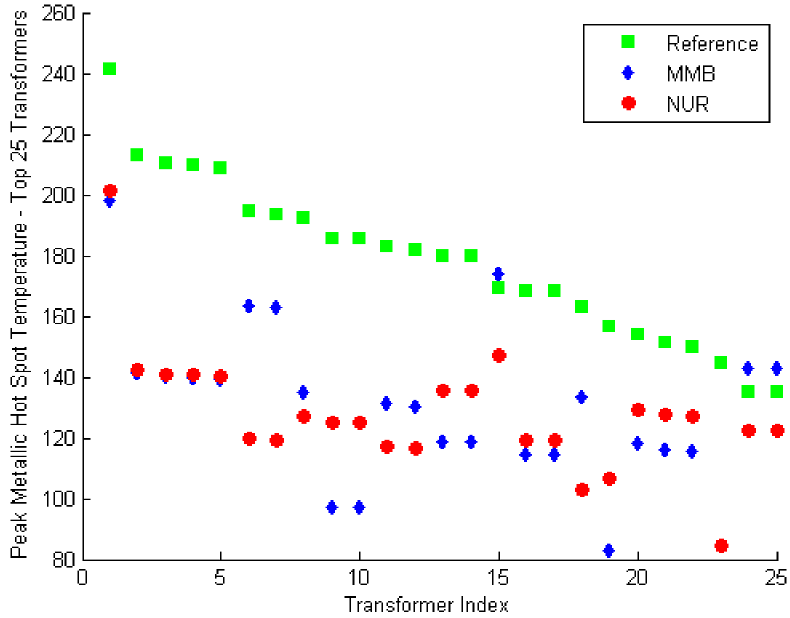


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

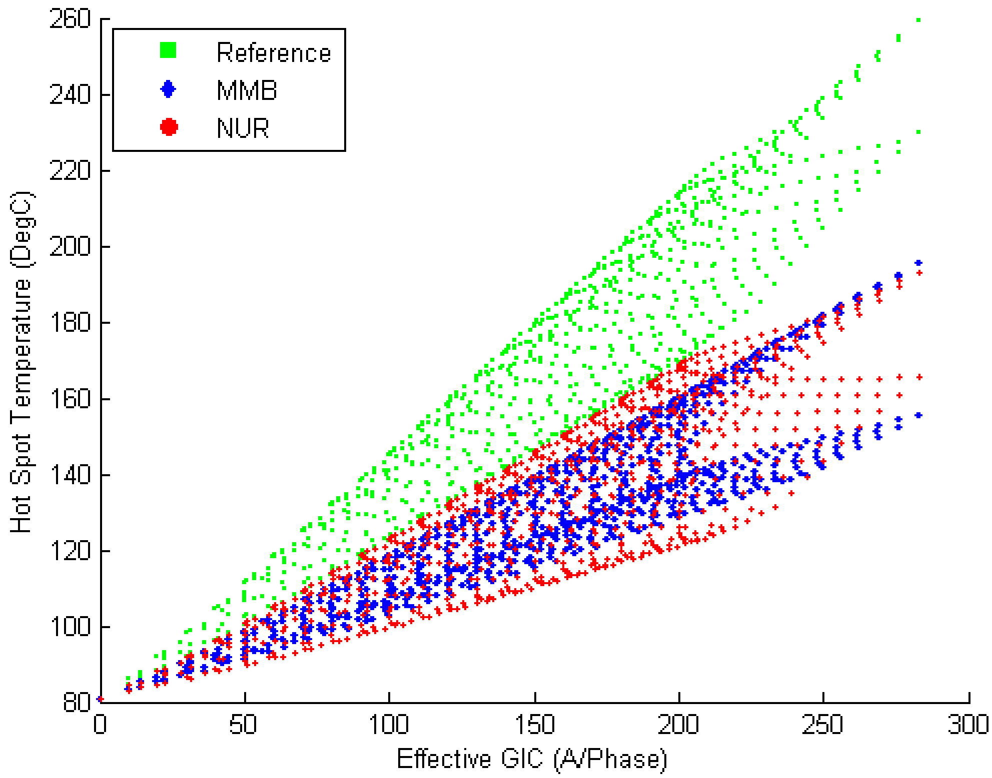


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for All Possible Circuit Orientations and Effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]. Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

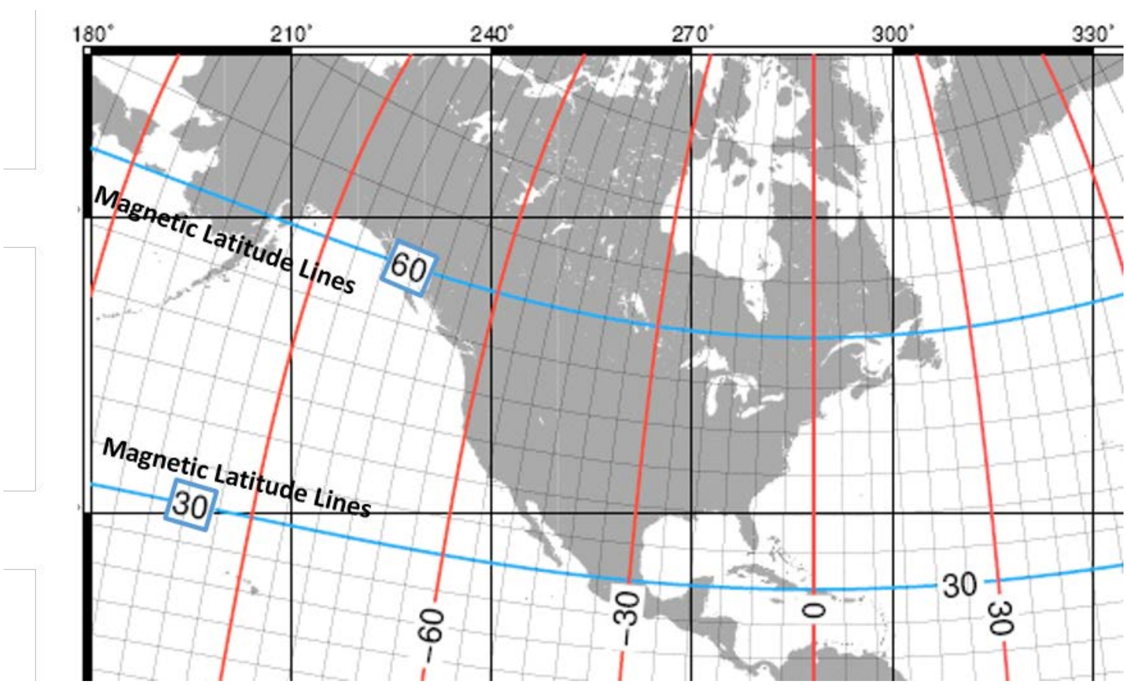


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \tag{II.2}$$

where,
* denotes convolution in the time domain,
z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,
$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,
$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

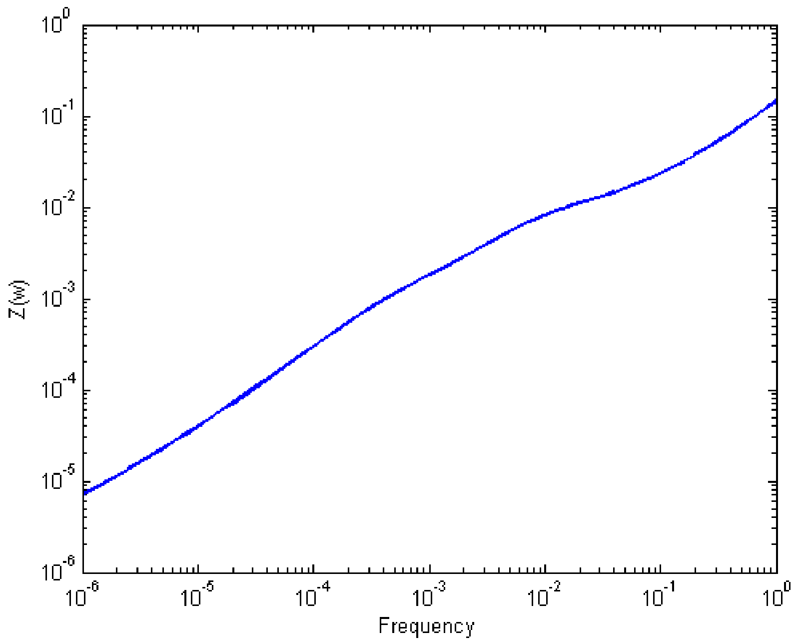


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

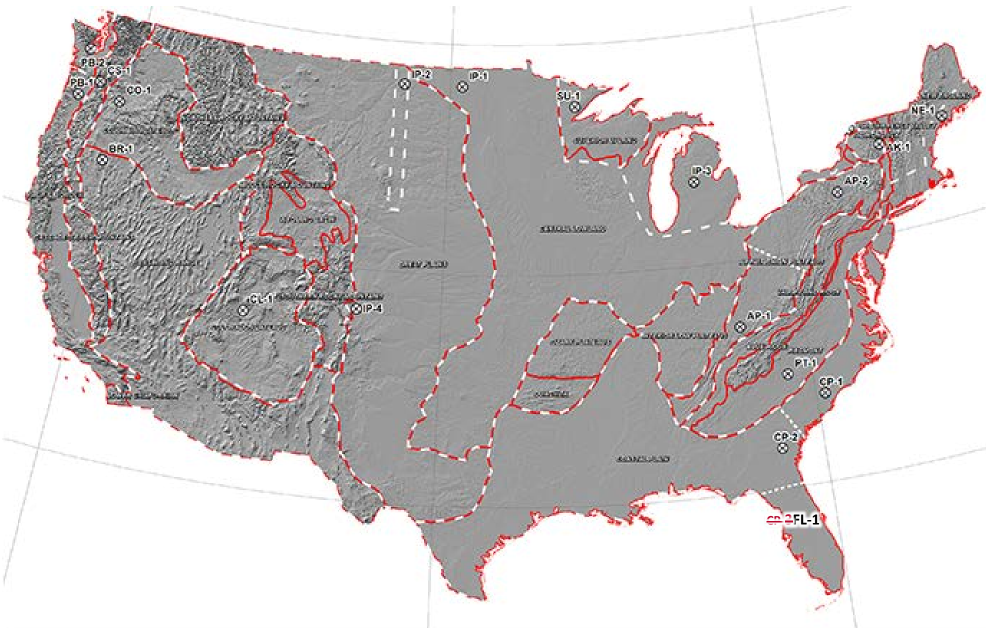
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use ~~a~~the largest β factor of ~~1~~adjacent physiographic regions or ~~other~~a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
~~CP3~~FL1	0.~~94~~74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

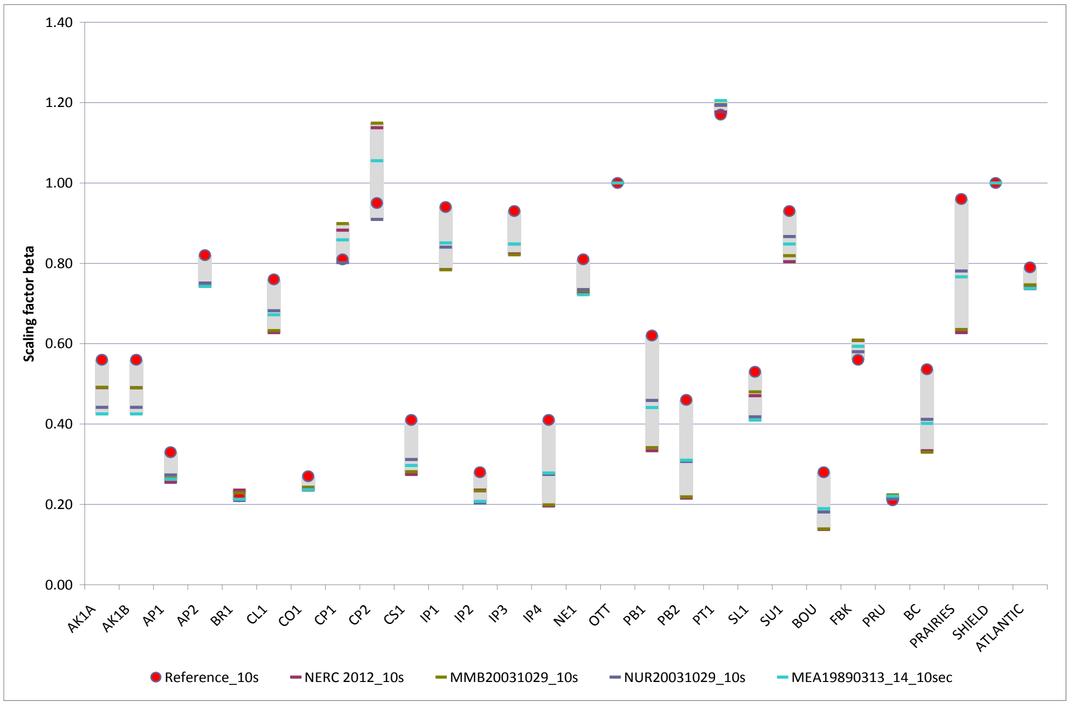


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V / km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V/km$$

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Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

This version, posted on October 30, 2014, contains a clarification on page 4 for the use of approved guidance from international standard-setting organizations.

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

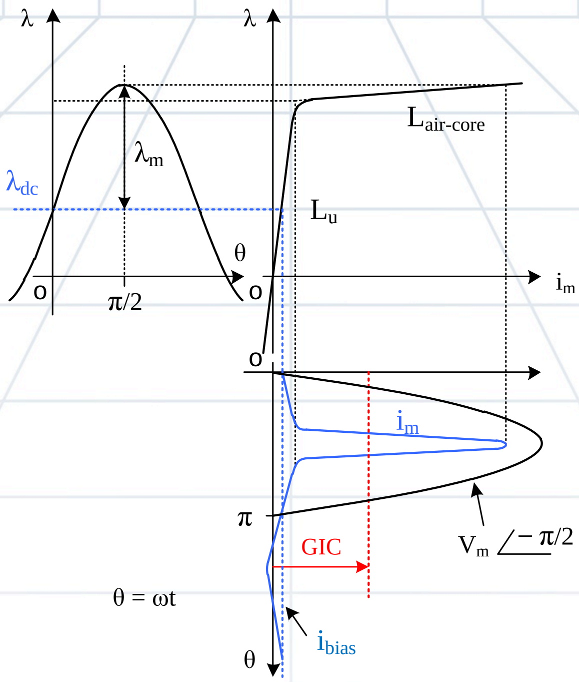

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \qquad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as **Table 1** below, provides the peak metallic hot spot temperatures that can be reached using conservative screening thermal models. To use **Table 1**, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

~~There are t~~Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer

capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

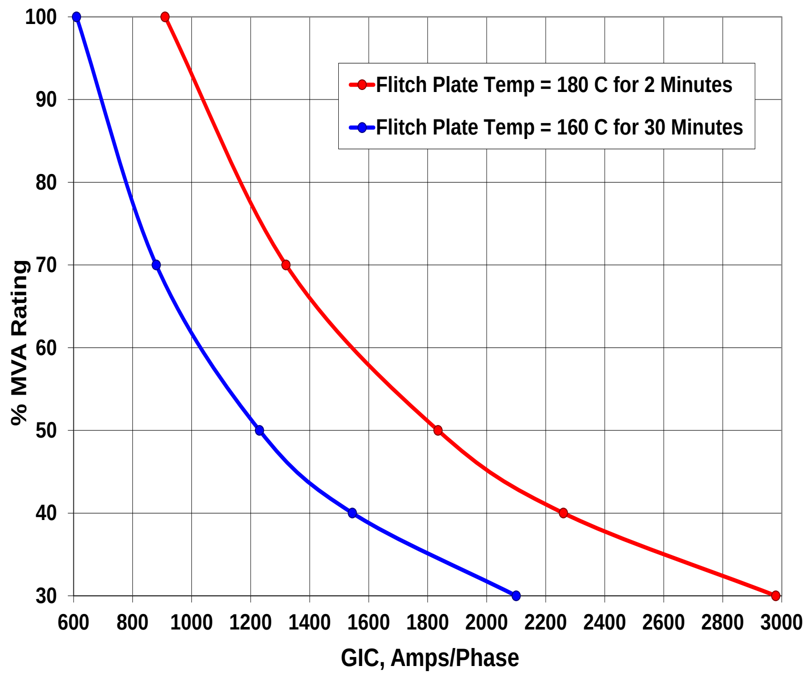

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

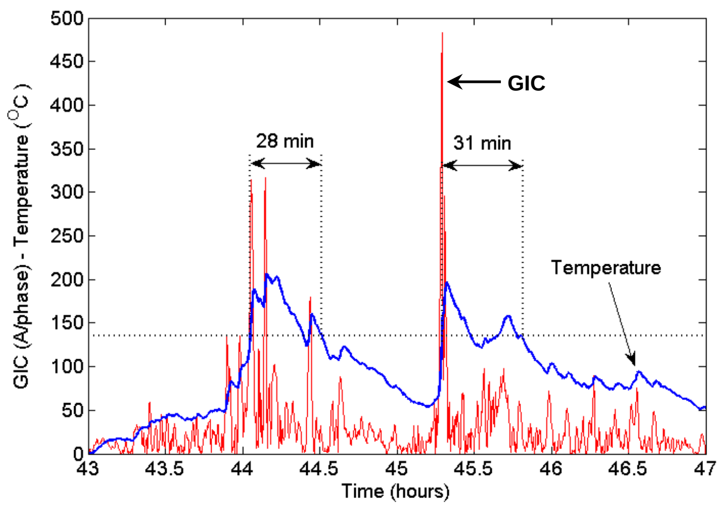

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \qquad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

---

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

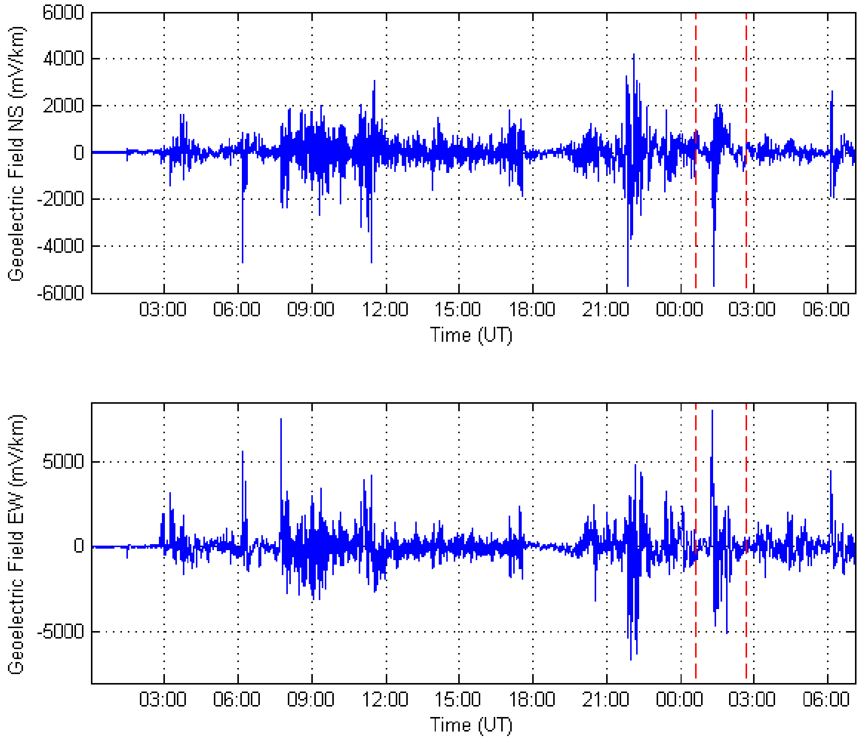

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

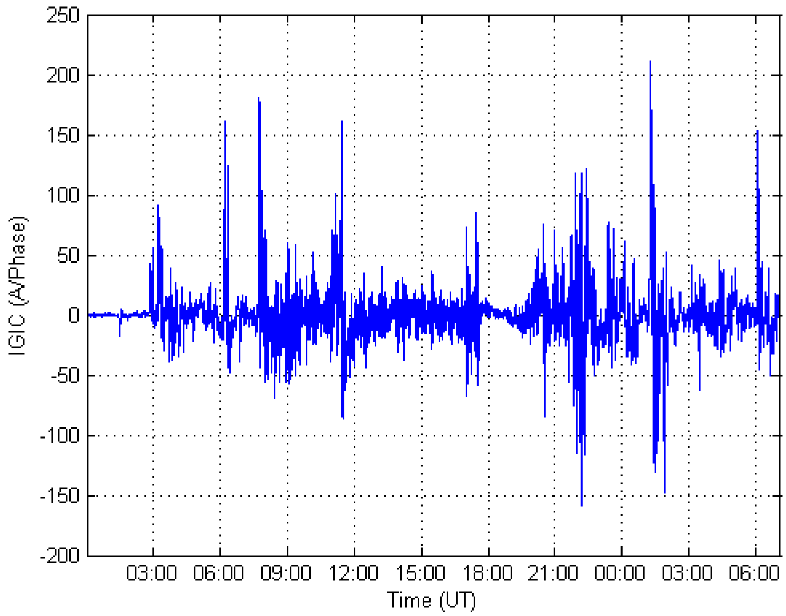

Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

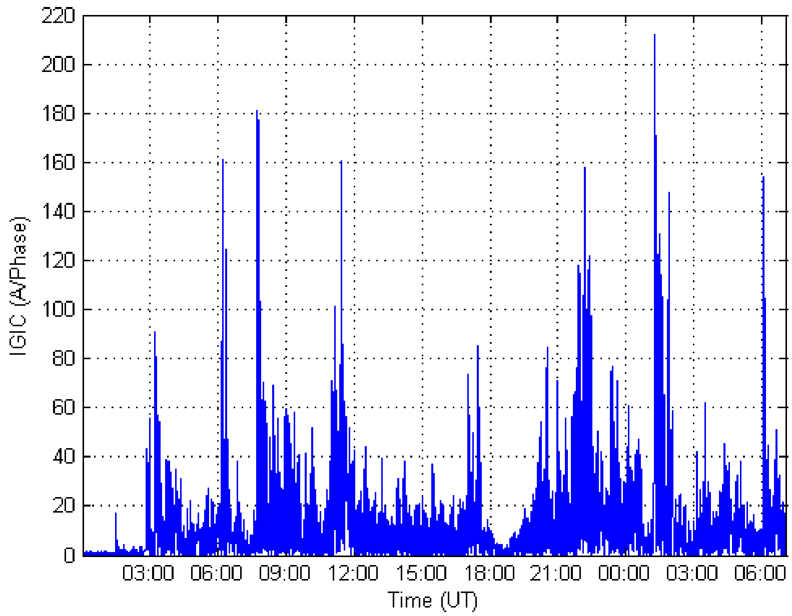

Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

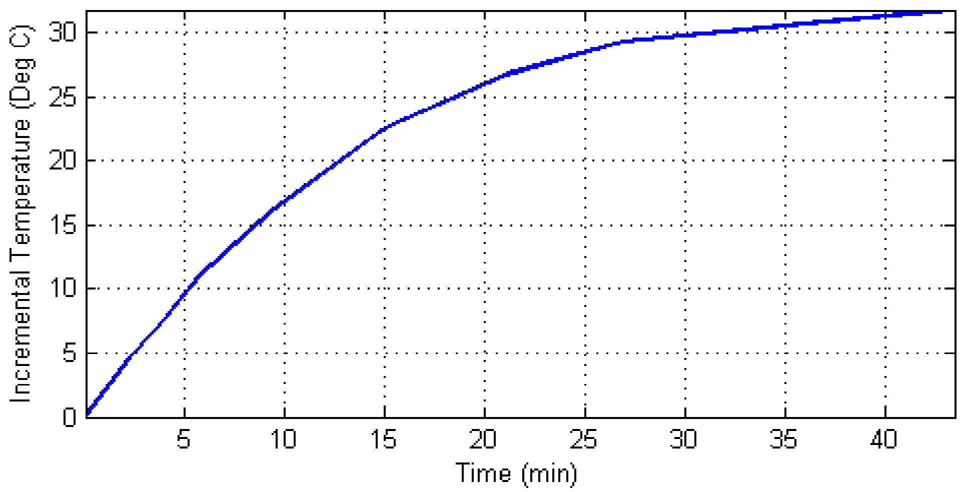

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step

Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

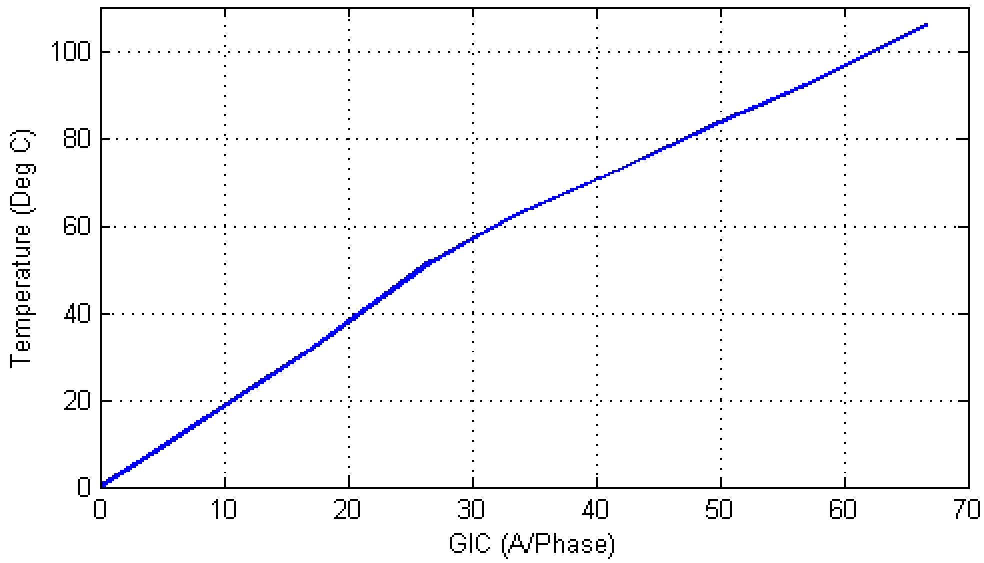

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

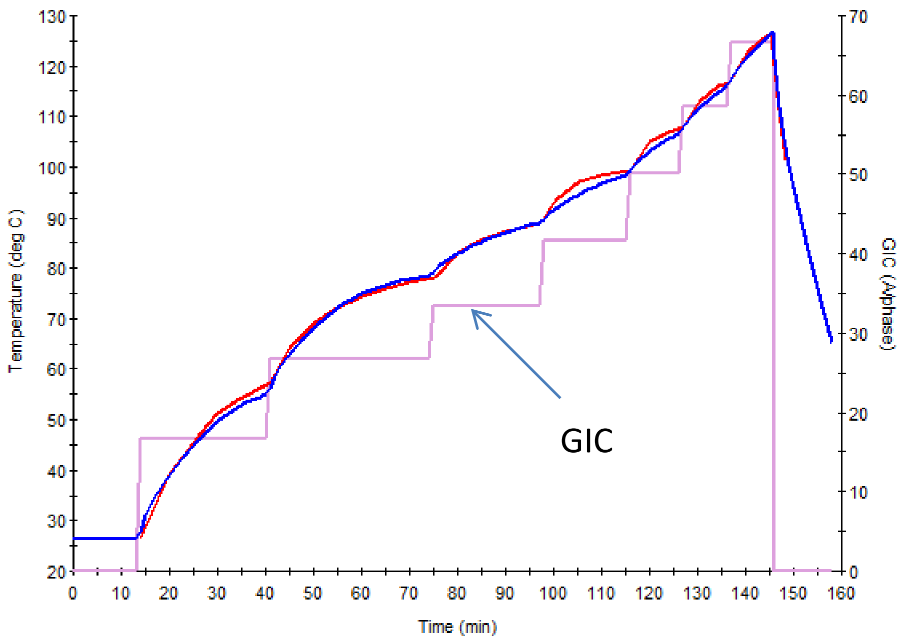

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

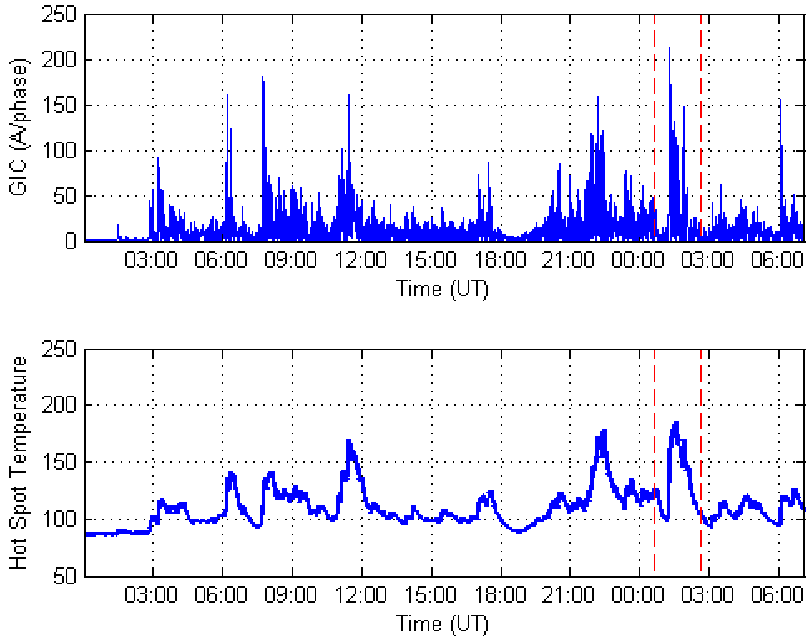

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

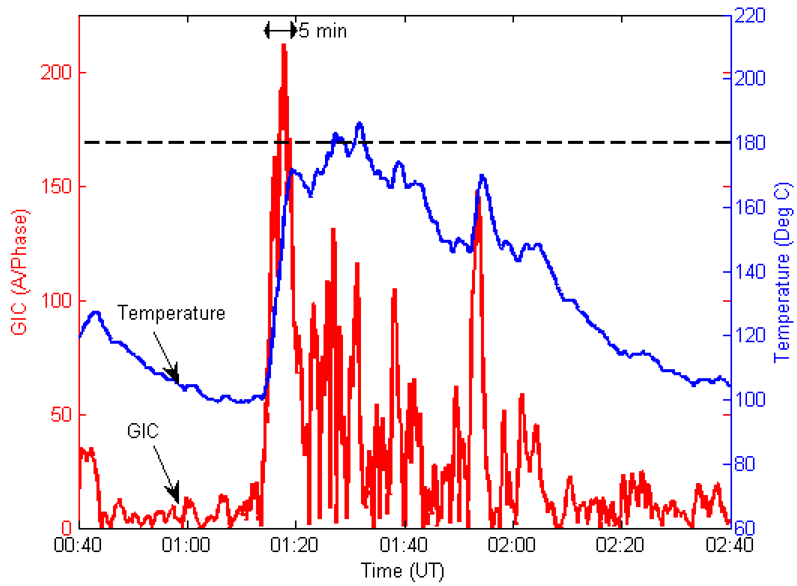

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is $\theta(t)$. Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

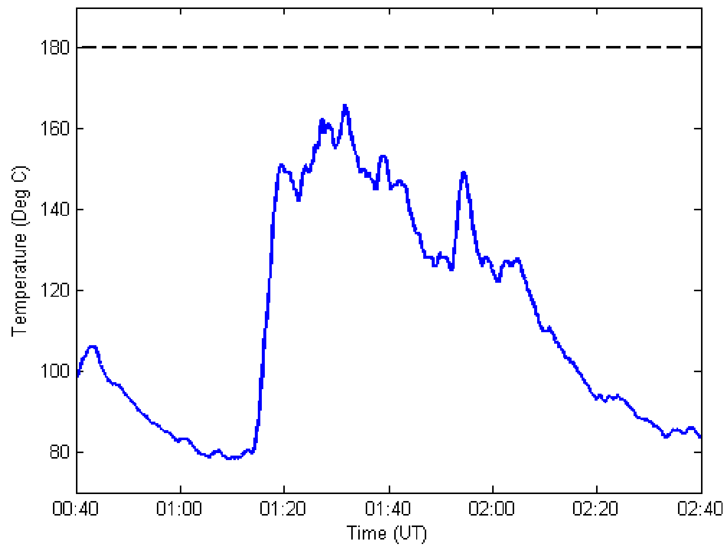

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std C57.91).

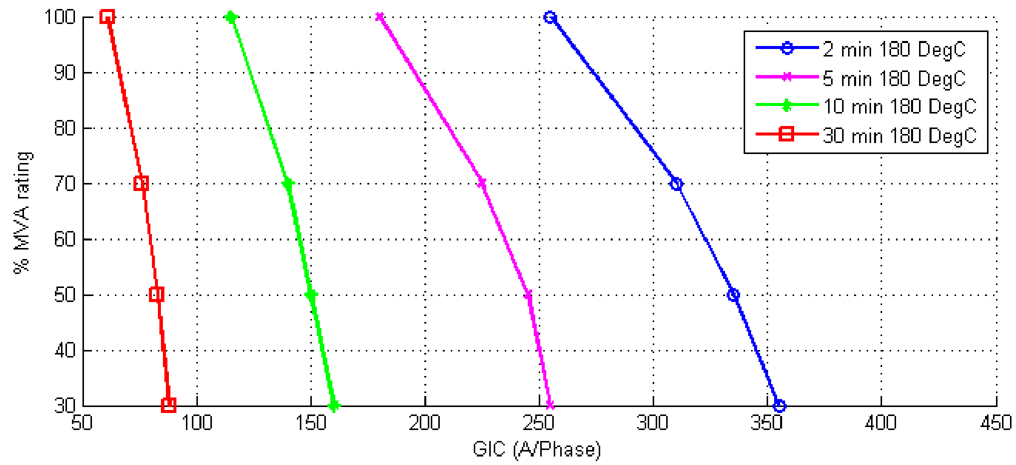

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

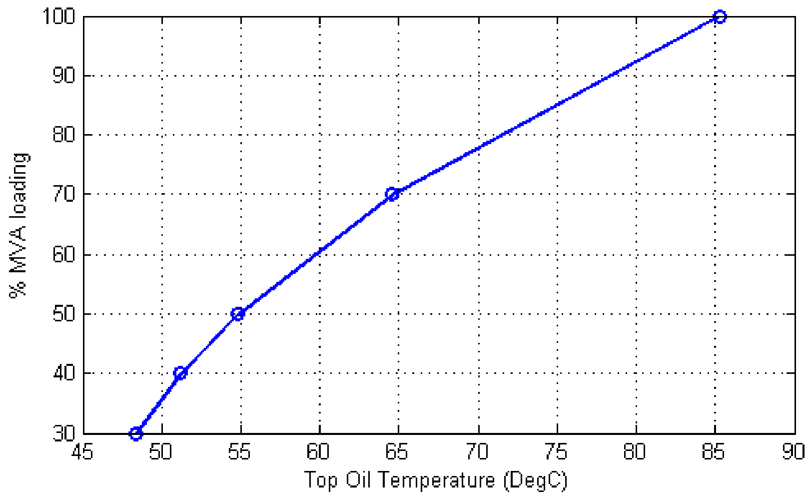

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

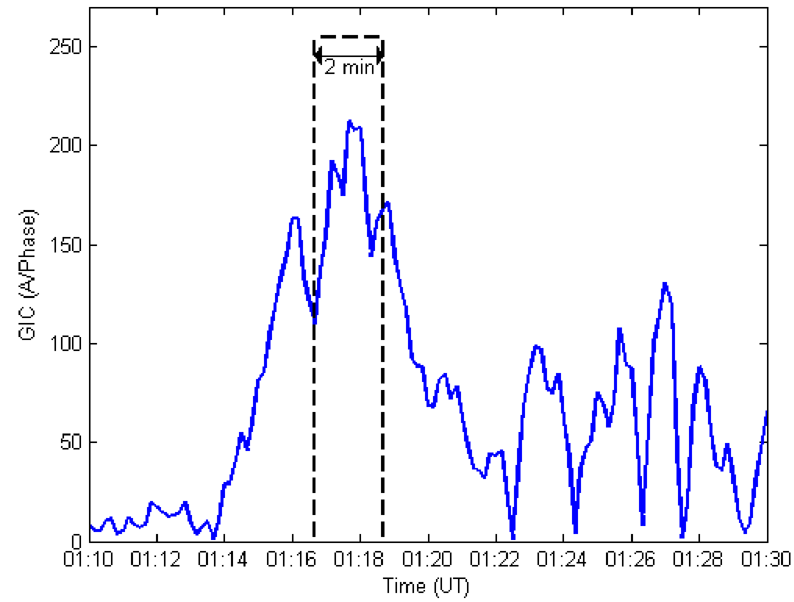

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

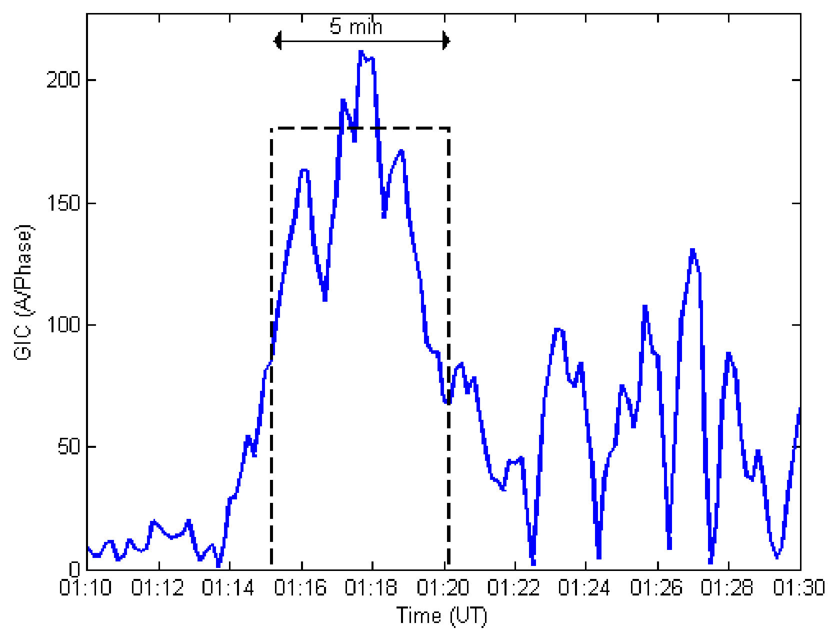

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

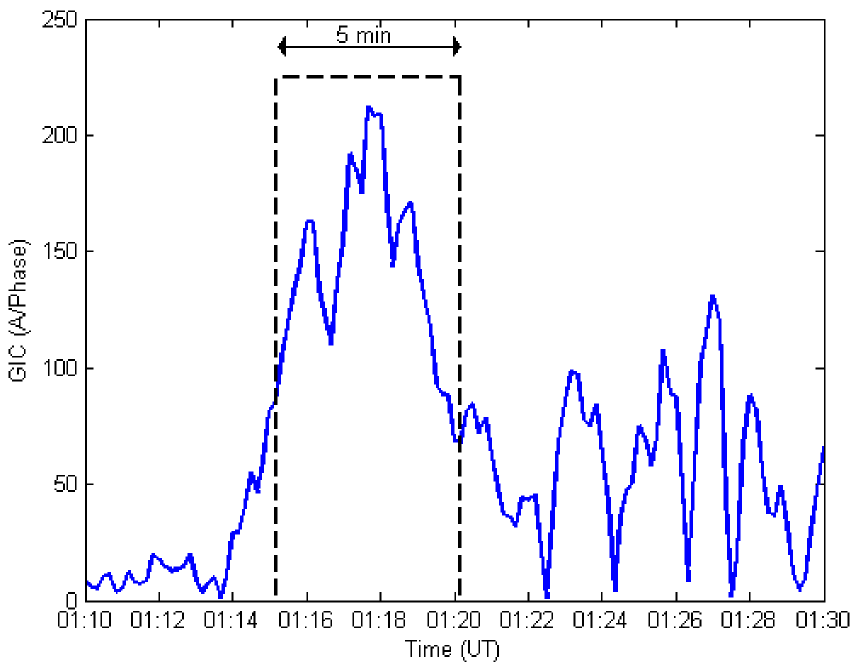

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[7] "Screening Criterion for Transformer Thermal Impact Assessment". paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformer Thermal Impact Assessment White Paper ~~(Draft)~~

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

This version, posted on October 30, 2014, contains a clarification on page 4 for the use of approved guidance from international standard-setting organizations.

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

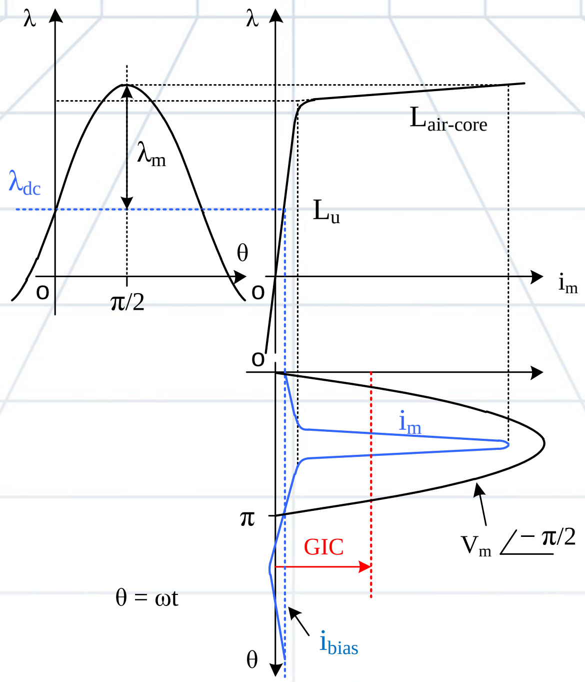

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std. C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \qquad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. -This table, shown as **Table 1** below, provides the peak metallic hot spot temperatures that can be reached using conservative screening thermal models. -To use **Table 1**, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. -If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

~~There are t~~Two different ways to carry out a detailed thermal impact ~~screening~~assessment are discussed below~~:~~. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer

capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

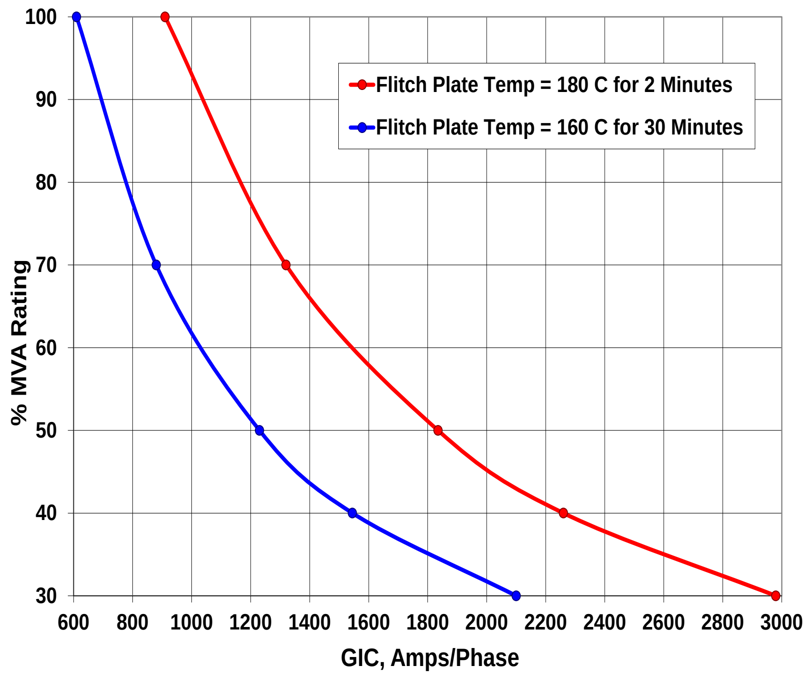

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std~~.~~ C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

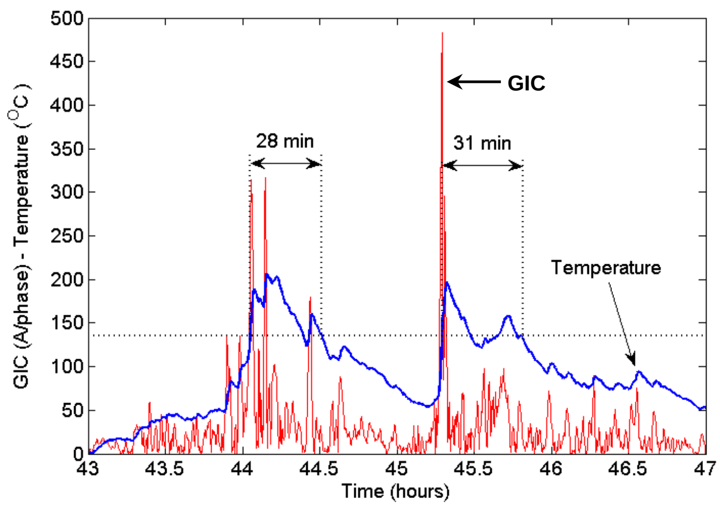

Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase~~/V/km~~) for any value of E_E(t) and E_N(t) can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \tag{2}$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

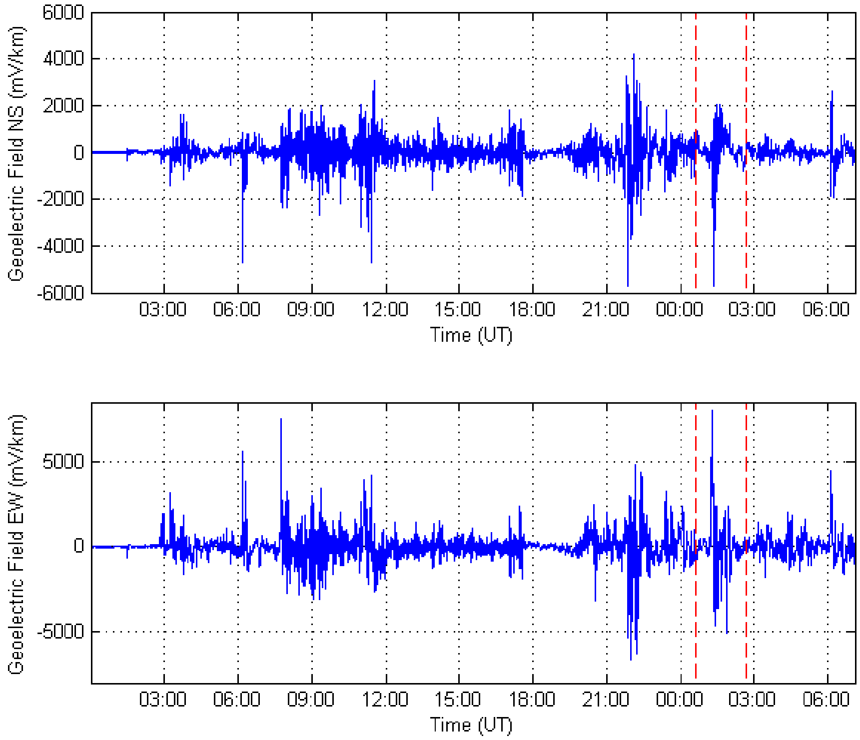

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming α=1 and β=1 (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

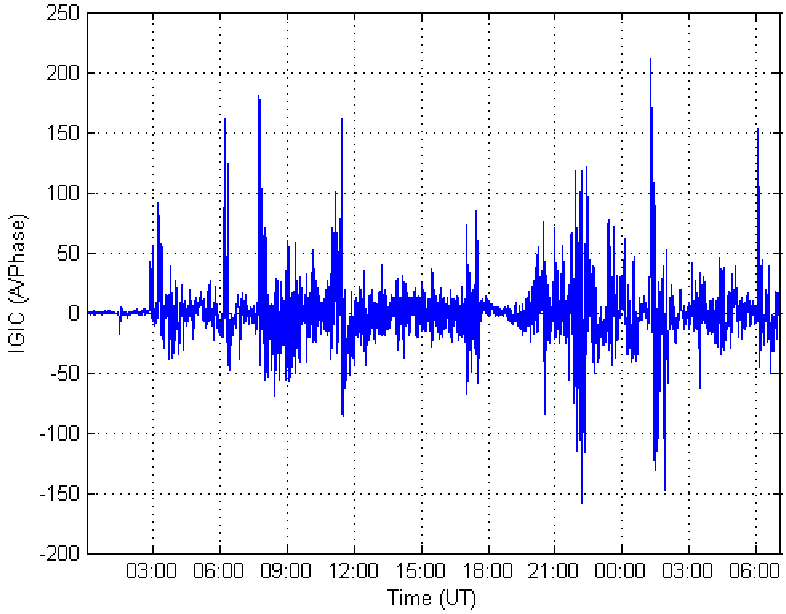

Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

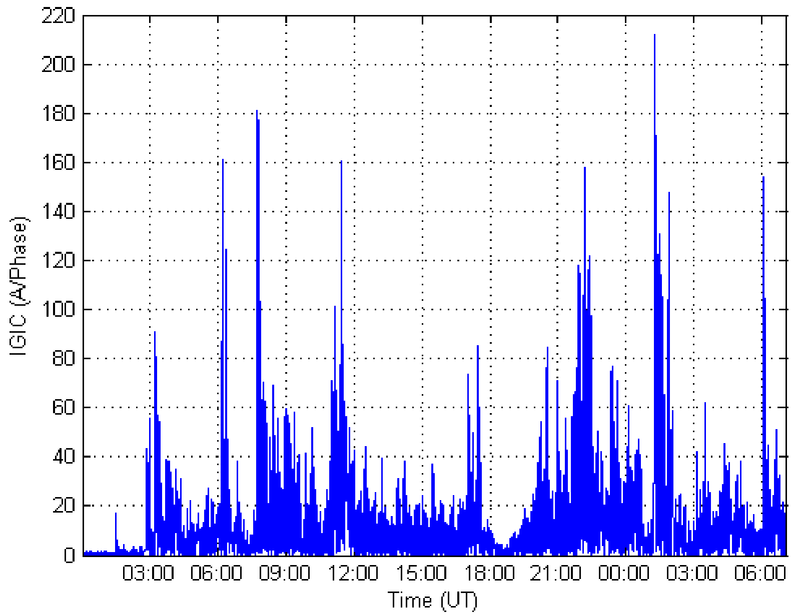

Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

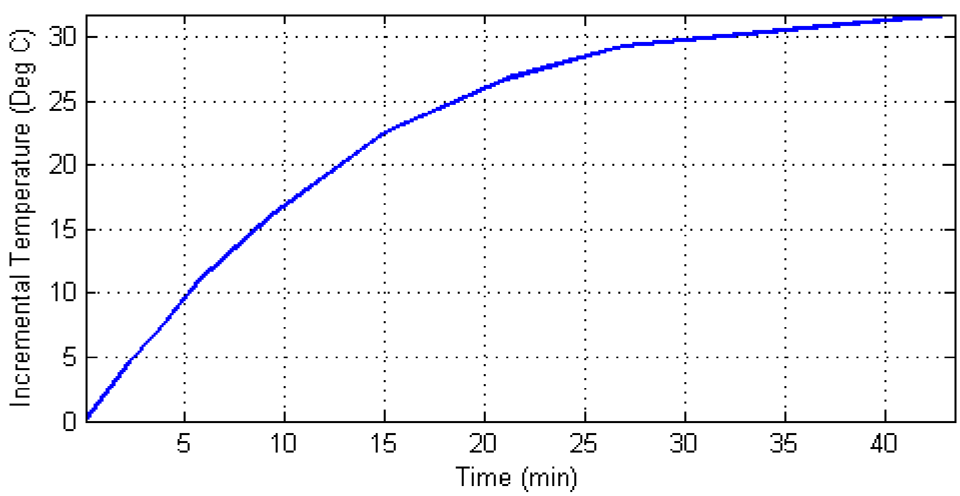

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

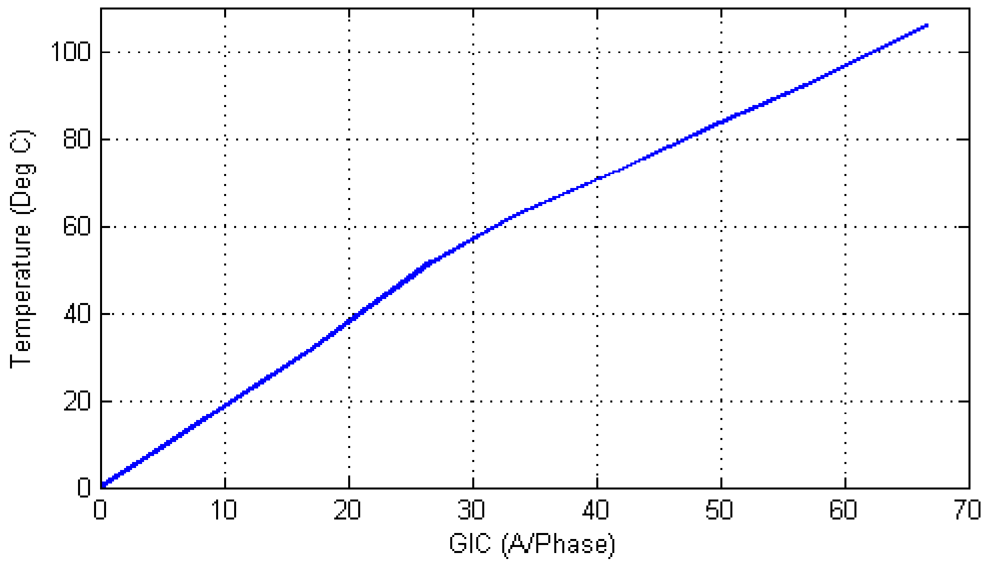

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

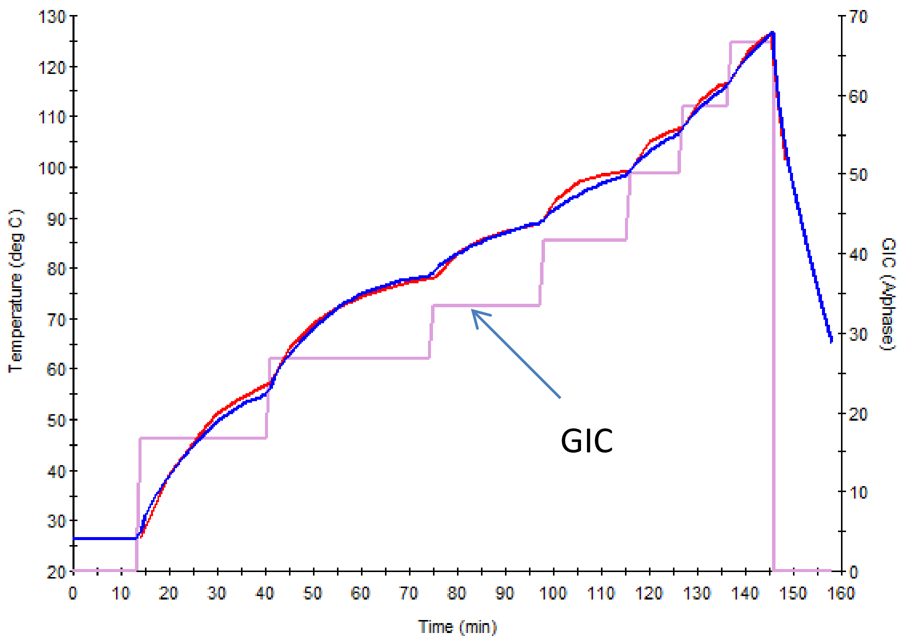

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time θ(t) for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

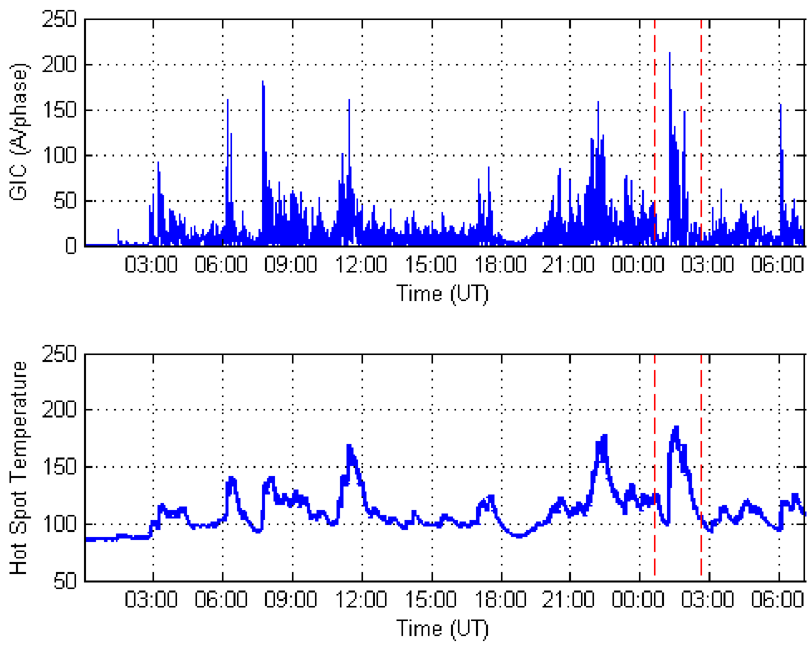

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

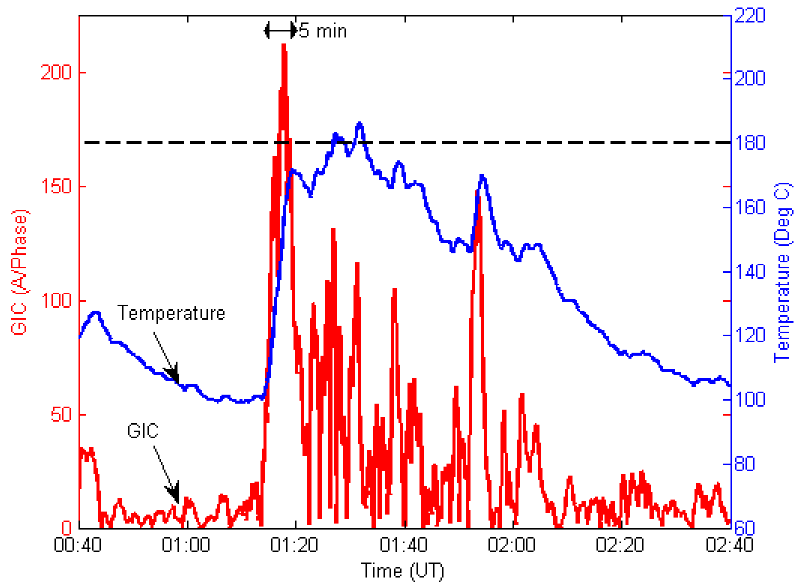

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std~~.~~ C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

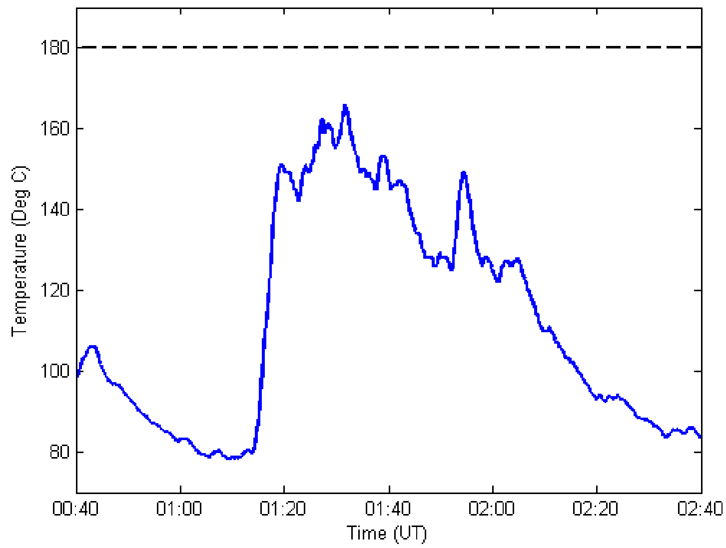

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std~~.~~ C57.91).

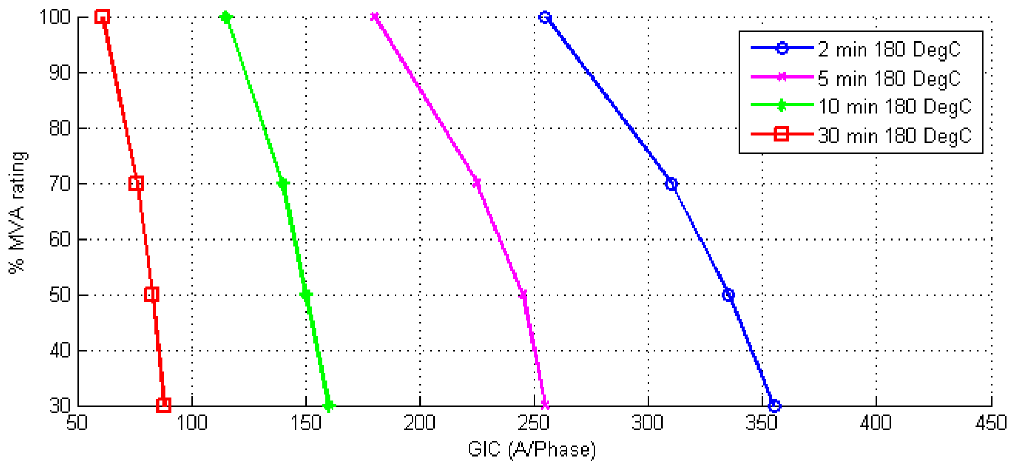

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

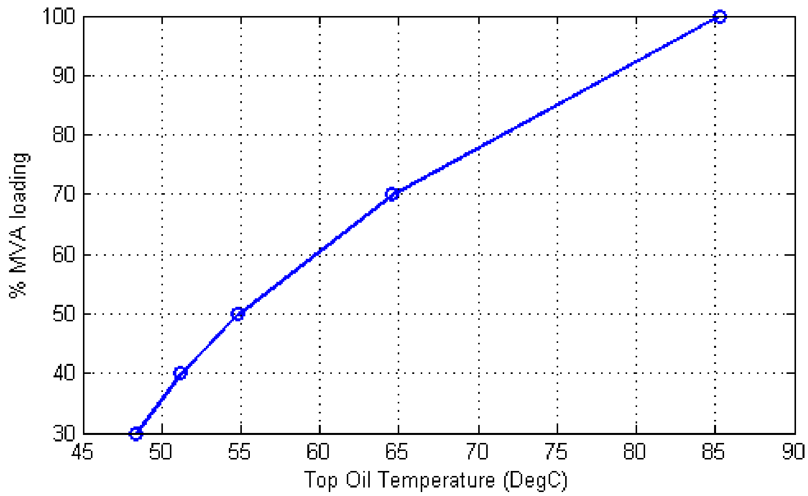

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

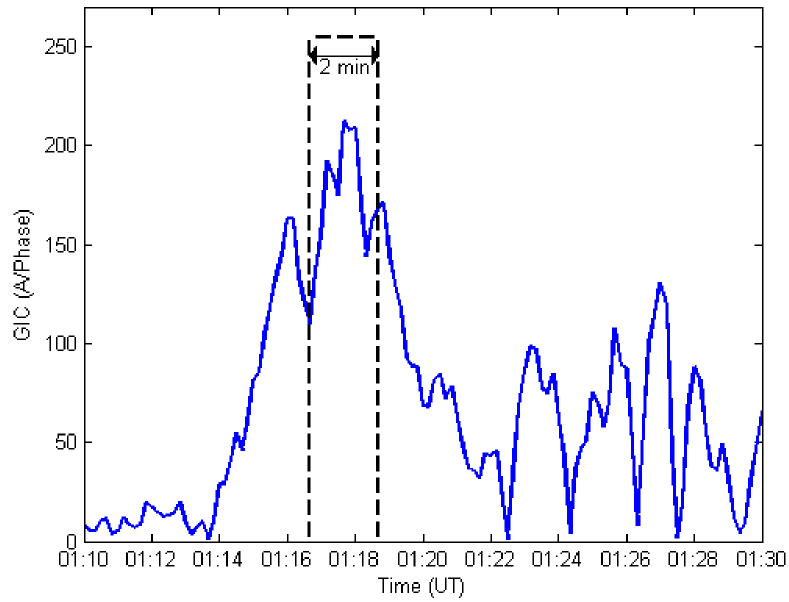

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

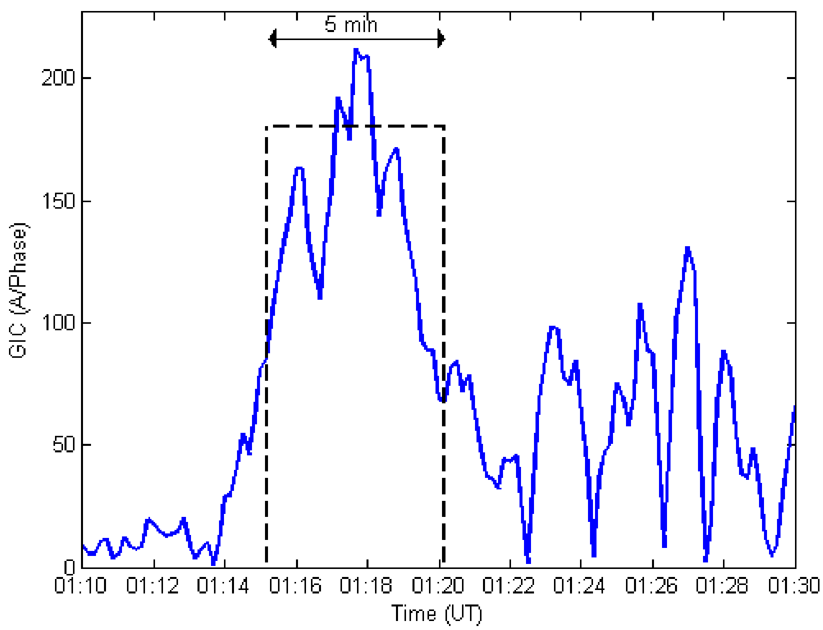

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

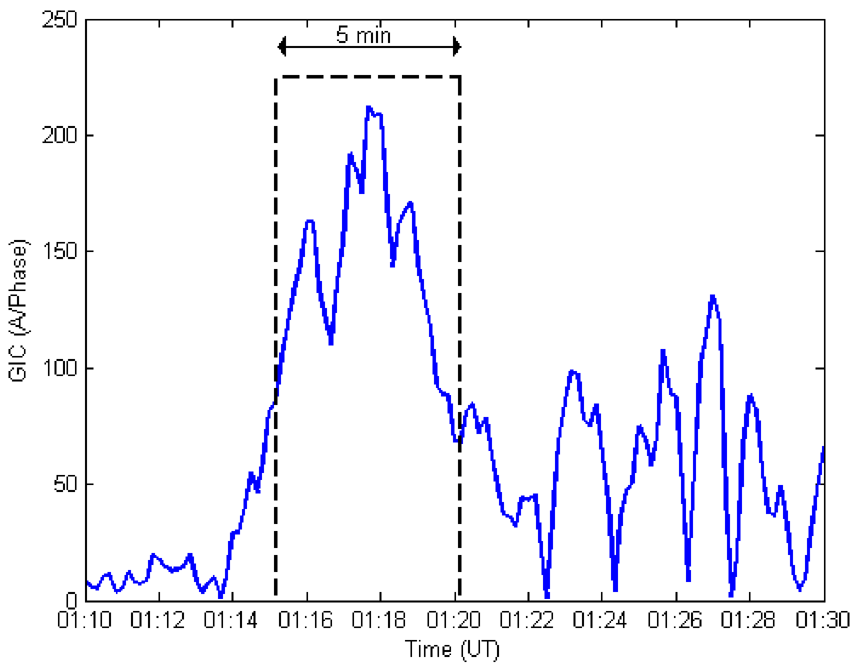

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

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[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

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[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[7] "Screening Criterion for Transformer Thermal Impact Assessment". paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \tag{1}$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (2)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (3)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (4)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**.

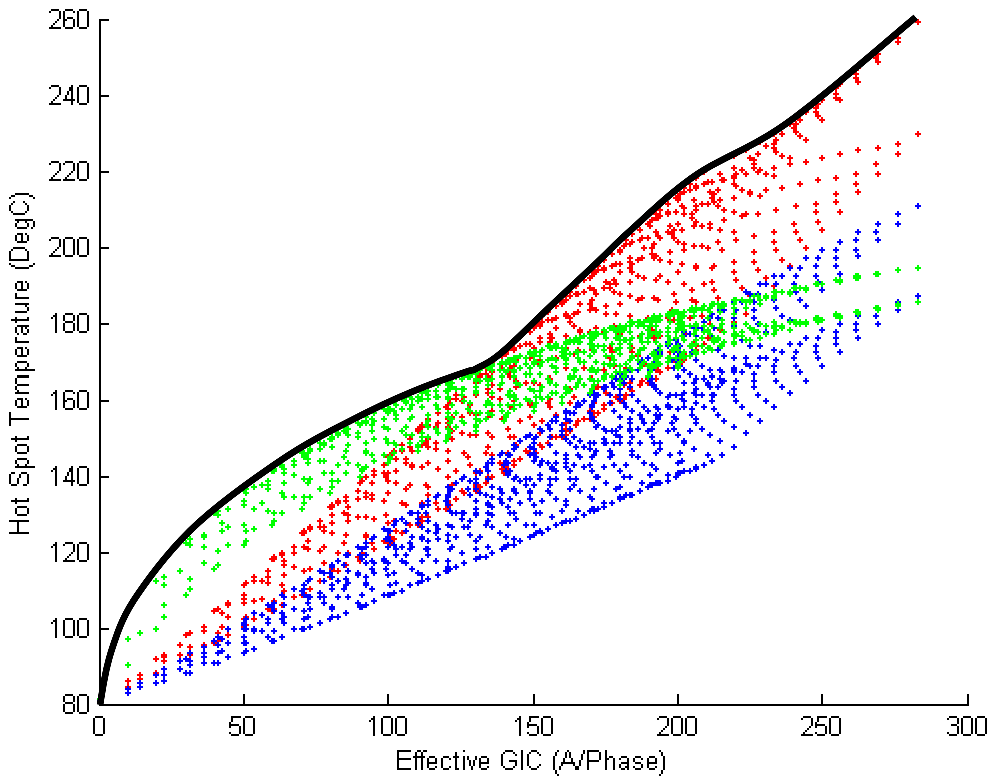

Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 104°C and 150°C when the bulk oil temperature is 80°C. The upper boundary of 150°C falls well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 150°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the condition of specific transformers where IEEE Std C57.91-2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the screening model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- The 75 A per phase screening threshold was determined on the basis of instantaneous peak hot spot temperatures. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.
- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

Appendix

The screening thermal model is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 2**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 3 and 4**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The third transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 5 and 6**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

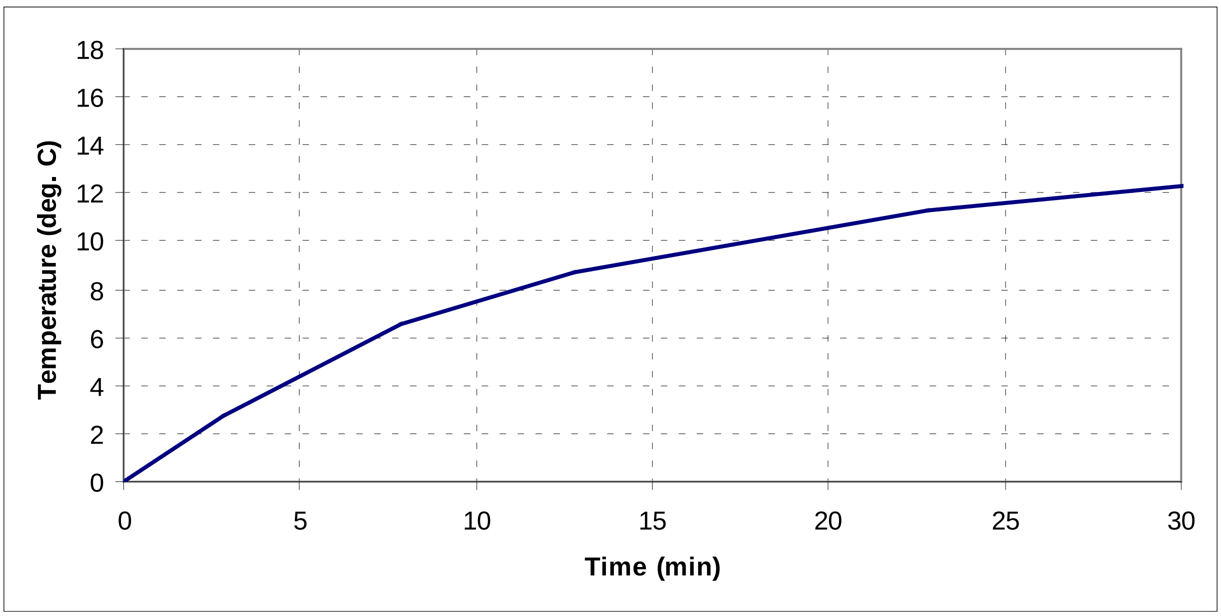

Figure 2: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

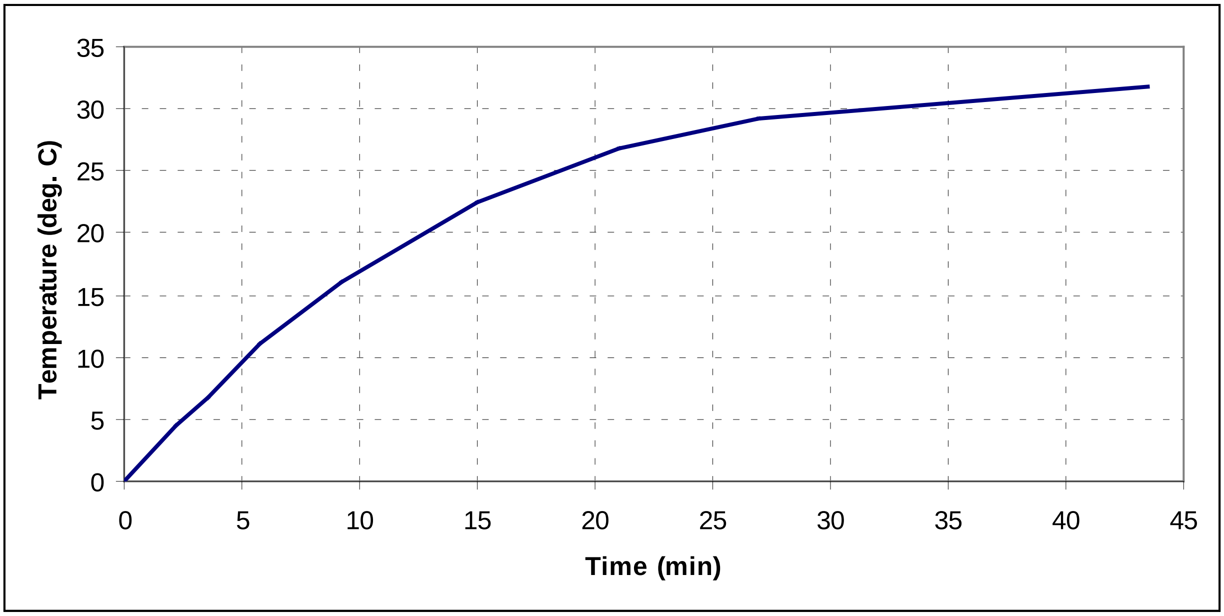

Figure 3: Step thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 10 A per phase dc step.

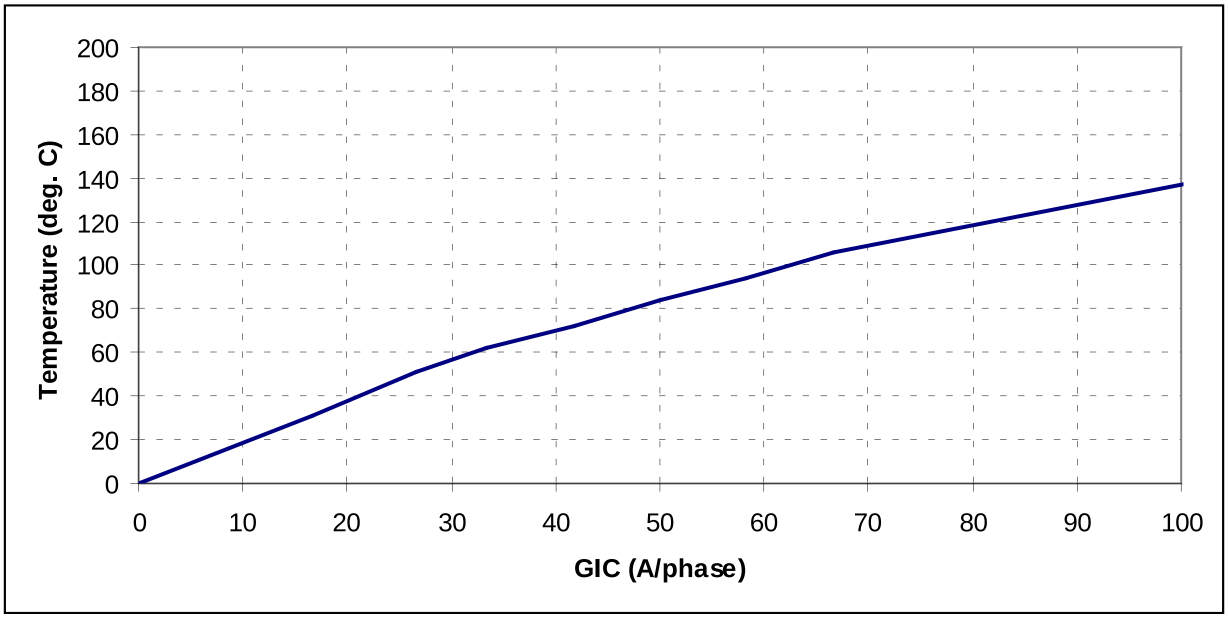

Figure 4: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

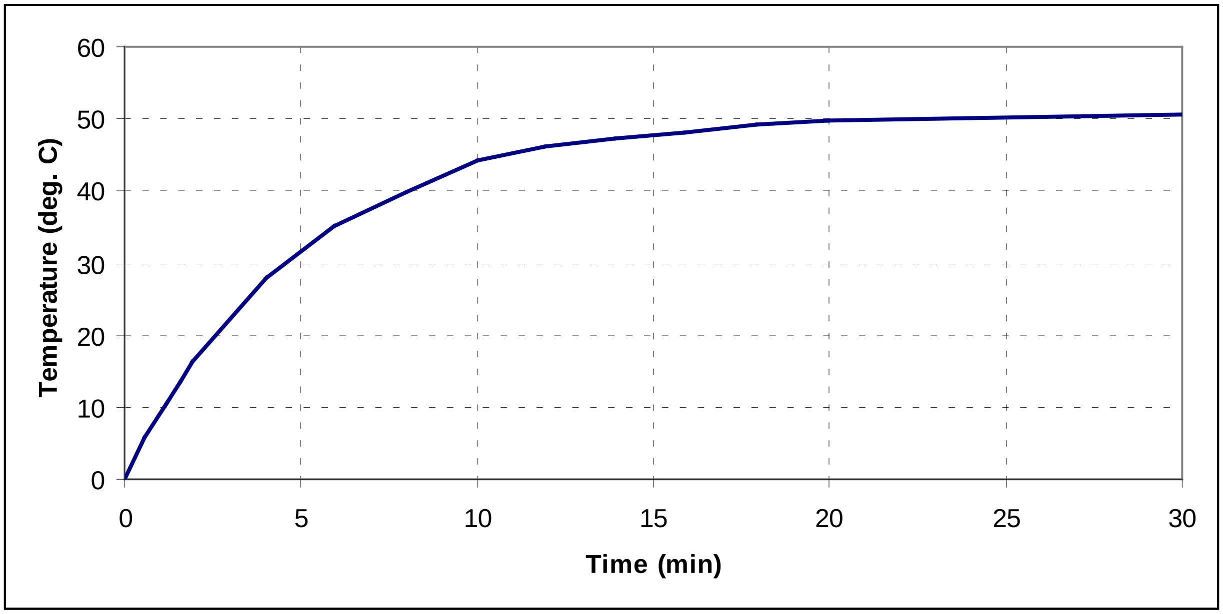

Figure 5: Step thermal response of tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

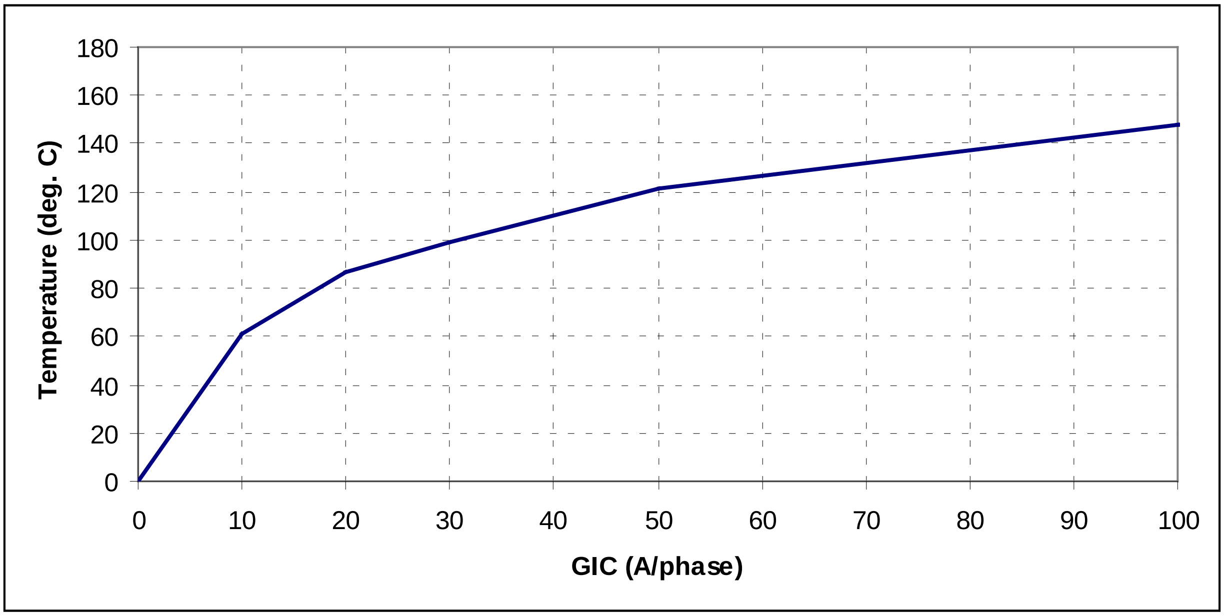

Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The composite envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event			
Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

For instance, if effective GIC is 150 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 180°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 60°C at maximum ambient temperature, then 210 A per phase of effective GIC translates in a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of GIC_E and GIC_N that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same screening model. For instance, the lower bound of peak temperatures for the screening model for 210 A per phase is 165°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[2] Marti, L., Rezaei-Zare, A., Narang, A., "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery,* vol.28, no.1, pp.320-327, Jan. 2013.

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Violation Risk Factor and Violation Severity Level Justifications

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk

Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities

- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications – TPL-007-1, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Low is consistent with approved TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-1 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A Violation Risk Factor of Low is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing GMD studies, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System under conditions of a GMD event.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its

			Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R7. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of High is consistent with the VRF for approved TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-1, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the GMD Vulnerability Assessment. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R2			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R2			
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to models for GMD Vulnerability Assessments. Approved TPL-001-4 Requirement R1 requires entities to maintain System models for Planning Assessments and has multiple subparts to form the basis for a graduated VRF. However, the System model for GMD Vulnerability Assessment will have most elements in common with the System model used for Planning Assessments in TPL-001-4. System models for GMD Vulnerability Assessment are distinguished primarily in that they account for reactive power losses due to GIC. Therefore, the subparts from approved TPL-001-4 Requirement R1 were not duplicated in proposed TPL-007-1 Requirement R2 and the VSL was not separated into further degrees of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R2	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-1 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during a benchmark GMD event; these criteria may be different from the voltage limits determined in approved TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-1, R3			
			System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.

VSL Justifications – TPL-007-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R5. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-1, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the BES meets performance criteria. Proposed TPL-007-1 Requirement R3 requires responsible entities to complete a GMD Vulnerability Assessment to ensure the system meets performance criteria during a benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in

Proposed VSLs – TPL-007-1, R4			
months since the last GMD Vulnerability Assessment.	Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	Requirement R4 Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

VSL Justifications – TPL-007-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R4	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A Violation Risk Factor of Medium is also consistent with approved IRO-010-1a Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-1 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R5			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R5			
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved MOD-032-1, Requirement R2 and IRO-010-1a, Requirement R3, which also have a graduated scale for VSLs.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R5	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with approved FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-1 Requirement R6 requires responsible entities to conduct a thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a thermal impact assessment for 5% or less or one	The responsible entity failed to conduct a thermal impact assessment for more than 5% up	The responsible entity failed to conduct a thermal impact assessment for more than 10%	The responsible entity failed to conduct a thermal impact assessment for more than 15%

Proposed VSLs – TPL-007-1, R6			
of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5.	to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include one of the required	up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include two of the required	or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5; OR The responsible entity failed to include three of the required elements as listed in

Proposed VSLs – TPL-007-1, R6			
	elements as listed in Requirement R6 Parts 6.1 through 6.3.	elements as listed in Requirement R6 Parts 6.1 through 6.3.	Requirement R6 Parts 6.1 through 6.3.

VSL Justifications – TPL-007-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved FAC-008-3, Requirement R6. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-1, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-1 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While approved TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-1 has split the requirements for performing a GMD Vulnerability Assessment and development of the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7 parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7 parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Stage 2

Order No. 779 Citation	Directive/Guidance	Resolution
P 2	Within 18 months of the effective date of this final rule, NERC must submit for approval one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.	The proposed standard requires applicable Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners to conduct periodic assessments of the impacts of a 100-year benchmark GMD event on their systems.
P 2	The Second Stage GMD Reliability Standard must identify what severity GMD events (i.e. benchmark GMD events) that responsible entities will have to assess for potential impacts on the Bulk-Power System.	The benchmark GMD event is described in the drafting team's white paper available on the project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx The benchmark provides a defined event for assessing system performance as required by the proposed standard. It defines the geoelectric field values used to compute geomagnetically-induced current flows for a GMD Vulnerability Assessment.
P 28	We expect that NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards.	The directive was met in the development of the proposed standard. The SDT chose a planning standard approach to meet the directives for the second stage GMD reliability standards, which allows responsible entities latitude to select mitigation from a variety of considerations which may include cost. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations. Comments on mitigation costs were solicited from stakeholders during formal comments and considered by the SDT.

Order No. 779 Citation	Directive/Guidance	Resolution
P 51	The Commission accepts the proposal in NERC's May 21, 2012 post-Technical Conference comments and directs NERC to "identify facilities most at-risk from severe geomagnetic disturbance" and "conduct wide-area geomagnetic disturbance vulnerability assessment" as well as give special attention to those Bulk-Power System facilities that provide service to critical and priority loads. As noted...owners and operators of the Bulk-Power System will perform the assessments.	When fully implemented, the proposed standard will enable wide-area assessment of GMD impact by owners and operators. Through the standard development process, industry has provided projections on the time required for obtaining validated tools, models, and data necessary for conducting GMD Vulnerability Assessments. The five-year phased Implementation Plan has been tailored accordingly and reflects a realistic timeline for expecting owners and operators to perform GMD Vulnerability Assessments. Corrective Action Plans required by the proposed standard provide the means to address risk to all facilities from a benchmark GMD event, not only those determined to be most at-risk in wide-area assessments. The proposed standard enhances NERC's ability to further assess the reliability risks that geomagnetic disturbances pose to the Bulk-Power System through the reliability assessment functions described in Section 800 of the NERC Rules of Procedure. During the five-year implementation period, NERC will closely support industry preparations, monitor implementation, and assess progress and initial results. Once the proposed standard is fully implemented, NERC and the Regional Entities will be better able to further assess the potential impacts of GMD events on the Bulk-Power System as a whole and update the 2012 Interim Report.
P 67	Each responsible entity under the Second Stage GMD Reliability Standards would then be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR [P 28 - 32] and adopted in this Final Rule.	The proposed standard requires applicable entities to perform assessments that will identify the impacts from benchmark GMD events on the interconnected transmission system. • Evaluation criteria are uniformly established in Requirement R4, Table 1, and Attachment 1.

Order No. 779 Citation	Directive/Guidance	Resolution
	• First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments... • Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers[1], including the effects of GICs originating from and passing to other regions. • Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues • Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed... • Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.	o Requirement R4 specifies system conditions. o Table 1 establishes uniform performance criteria. o Attachment 1 describes the procedure for calculating the benchmark GMD event for use in the GMD Vulnerability Assessment. • Requirements R4 and R6 address assessments of the effects of GIC on applicable transformers. o Requirement R4 specifies that responsible planning entities must conduct GMD Vulnerability Assessments that include steady state analysis to ensure transformer reactive losses from a benchmark GMD event do not produce voltage collapse, Cascading, and uncontrolled islanding. o Requirement R6 specifies that Transmission Owners and Generator Owners must conduct thermal impact assessments of applicable power transformers. • Requirements R4 and Table 1 address assessments of the effects of GIC on other Bulk-Power System equipment. Table 1 specifies that Reactive Power compensation devices and other Transmission Facilities are removed in the GMD study as a result of Protection System operation or Misoperation due to harmonics. Thus the GMD Vulnerability Assessment includes the system effects caused by GIC impacts on other BPS equipment. • The proposed standard accounts for wide-area impacts by requiring information exchange and involving appropriate applicable entities. Requirement R4 and Requirement R7 specify that GMD Vulnerability Assessments and Corrective Action Plans must be provided to Reliability Coordinators, adjacent planning entities, and functional entities

[1] The NOPR described damage to Bulk-Power System components as a primary effect of GICs and production of harmonics that are not present during normal Bulk-Power System operation and increased transformer absorption of reactive power as secondary effects of GICs. NOPR, 141 FERC ¶ 61,045 at P 13.

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		specifically referenced in the plans. Reliability Coordinators work together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function. Planning Coordinators integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. • The proposed standard requires GMD Vulnerability Assessments to be periodically updated, not to exceed every 60 calendar months.
P 67	The NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate assessments across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness.	Planning Coordinators are included as applicable entities in the proposed standard to integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. Requirement R1 in the proposed standard requires the Planning Coordinator to "identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s)". Requirement R4 specifies that GMD Vulnerability Assessments are provided to adjacent Planning Coordinators. Requirement R7 specifies that Corrective Action Plans are provided to adjacent Planning Coordinators. These requirements provide the necessary information exchange for planning activities. In addition, the proposed standard designates Reliability Coordinators as a recipient of GMD Vulnerability Assessments and Corrective Action Plans. Reliability Coordinators work

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		together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function.
P 68	NERC should consider developing Reliability Standards that can incorporate improvements in the scientific understanding of GMDs. When developing the Second Stage GMD Reliability Standards implementation schedule, NERC should consider the availability of validated tools, models, and data necessary to comply with the Requirements.	The requirements in the proposed standard are performance-based which allow applicable entities to use state of the art tools and methods to accomplish the specified reliability objectives. The standard does not contain prescriptive requirements for entities to use specific tools, models, or procedures which would limit the applicability of improvements in scientific understanding. Furthermore the use of modern magnetometer data and statistical methods in determining the benchmark GMD event supports reevaluation as additional magnetometer data is collected during future solar cycles. The 5-year phased implementation period was developed with consideration for the availability of validated tools, models, and data required by applicable entities.
P 79	If the assessments identify potential impacts from benchmark GMD events, owners and operators must develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event. • Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training alone, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the benchmark GMD events	The directive is met by requiring an entity to develop a Corrective Action Plan in the event its system fails to meet specified performance criteria. Requirement 7 part 7.1 lists acceptable actions which are not limited to considering Operating Procedures or enhanced training.

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	based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.	
P 82	As with the First Stage GMD Reliability Standards, the responsible entities should perform vulnerability assessments of their own systems and develop the plans for mitigating any identified vulnerabilities. We take no position in this Final Rule on which functional entities should be responsible for compliance under the Second Stage GMD Reliability Standards. However, the NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate mitigation plans across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness. We clarify that if a responsible entity performs the required GMD vulnerability assessments and finds no potential GMD impacts, no plan is required under the Second Stage GMD Reliability Standards.	The proposed standard requires applicable entities to conduct assessments on their systems and develop plans to mitigate identified vulnerabilities. In Requirement R1, Planning Coordinators and Transmission Planners identify responsibilities for maintaining models and performing studies needed for GMD Vulnerability Assessments specified in Requirement R4. In Requirement R6, Transmission Owners and Generator Owners are required to conduct thermal impact assessments of applicable power transformers and, if necessary, specify mitigating actions. Requirement R7 specifies that the applicable planning entity must develop a Corrective Action Plan in the event that it concludes through the GMD Vulnerability Assessment that the system does not meet performance requirements. An entity that performs a GMD Vulnerability Assessment and does not identify a deficiency in system performance is not required to develop a Corrective Action Plan.
P 84	The Second Stage GMD Reliability Standards should not impose "strict liability" on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity.	The proposed standard is a planning standard where the benchmark GMD event is the planning basis. The standard does not impose strict liability on failure to ensure reliable operation during a GMD event of unforeseen severity.
P 85	Given that some responsible entities have or may choose automatic blocking measures, the NERC standards development process should consider how to verify that selected blocking measures are effective and consistent with the reliable operation of the Bulk-Power System.	The GMD Vulnerability Assessment process considers all mitigation measures in modeling, assessment, and mitigation requirements. Requirement R2 specifies that responsible entities shall maintain system models for performing GMD Vulnerability

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		Assessments, which will include automatic blocking measures that are part of the system as described in the technical guidance. The responsible entity must perform studies based on these models as required in Requirement R4 to verify effectiveness and the reliable operation of the system. When a responsible entity identifies a need for mitigation actions such as blocking measures, Requirement R6 and R7 specify that information must be shared with planning entities to ensure that the mitigation actions are consistent with reliable operation.
P 86	While responsible entities will decide how to mitigate GMD vulnerabilities on their systems, the NERC standards development process should consider how the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic measures including, for example, some combination of blocking, improved "withstand" capability, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.	The directive is met in Requirement R7. Responsible entities that conclude through the GMD Vulnerability Assessment that their System does not meet performance requirements are required to develop a Corrective Action Plan. The plan must list deficiencies and the associated actions needed to achieve required performance. Requirement R7 provides examples of such actions: installation or modification of equipment, use of Operating Procedures, and other actions specified in the requirement.
P 91	NERC must propose an implementation plan.	The implementation plan was developed through the standards development process.
P 91	We do not direct or suggest a specific implementation plan. As stated in the NOPR, in a proposed implementation plan, we expect that NERC will consider a multi-phased approach that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable operation of the Bulk-Power System are protected first. We also expect, as discussed above, that the implementation plan will take into account the availability of validated tools, models, and data that are necessary for	Compliance with the proposed standard is to be implemented over a 5-year period as described in the Implementation Plan. Phased implementation provides • Necessary time for entities to obtain tools, models, and data required for GMD vulnerability assessments • Proper sequencing of system and equipment assessments performed by various applicable functional entities to build an overall assessment of GMD vulnerability.

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	responsible entities to perform the required GMD vulnerability assessments.	• Adequate time for development of viable Corrective Action Plans that detail actions and timelines necessary to achieve required performance. Development of Corrective Action Plans may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc. to meet the TPL-007-1 requirements.

NERC
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RELIABILITY CORPORATION

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Formal Comment Period Now Open through November 21, 2014

Now Available

A 25-day formal comment period for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern, Friday, November 21, 2014**.

The Standards Committee (SC) authorized a waiver to shorten the comment period for TPL-007-1 from 45 days to 25 days, with an additional ballot and non-binding poll to be conducted during the last 10 days of the comment period. The notice of waiver request presented to the SC for consideration is posted on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 12-21, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson, Standards Developer, or via telephone at 404-446-2560.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

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Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 12-21, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
TPL-007-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, November 21, 2014**.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results	Non-Binding Poll Results
Quorum /Approval	Quorum/Supportive Opinions
79.73% / 77.29%	78.78% / 69.67%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Mark Olson, or by telephone at 404-446-9760.

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Ballot Results	
Ballot Name:	Project 2013-03 GMD TPL-007-1
Ballot Period:	11/12/2014 - 11/21/2014
Ballot Type:	Additional
Total # Votes:	299
Total Ballot Pool:	375
Quorum:	**79.73 % The Quorum has been reached**
Weighted Segment Vote:	77.29 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	107	1	59	0.766	18	0.234	0	4	26
2 - Segment 2	8	0.6	5	0.5	1	0.1	0	1	1
3 - Segment 3	86	1	45	0.763	14	0.237	0	6	21
4 - Segment 4	24	1	15	0.833	3	0.167	0	2	4
5 - Segment 5	79	1	45	0.763	14	0.237	0	6	14
6 - Segment 6	54	1	33	0.786	9	0.214	0	5	7
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	5	0.5	2	0.2	3	0.3	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.6	5	0.5	1	0.1	0	0	1
Totals	**375**	**7**	**212**	**5.411**	**63**	**1.589**	**0**	**24**	**76**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
				SUPPORTS

1	KAMO Electric Cooperative	Walter Kenyon	Negative	THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see comments submitted by Hydro Quebec and NPCC RSC.)
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD's Mahmood Safi)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker		
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL Corporation NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe Seabrook, Puget Sound

				Energy)
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments submitted by Maryclaire Yatsko)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	California ISO	Rich Vine	Negative	COMMENT RECEIVED
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN		
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	

3	City of Clewiston	Lynne Mila		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi - OPPD)

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
				SUPPORTS THIRD PARTY COMMENTS - (Seminole

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	Electric Cooperative Comments submitted by Maryclaire Yatsko)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - (DTE Electric)
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	

5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	COMMENT RECEIVED
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joseph Seabrook)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Maryclaire Yatsko)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Southern Indiana Gas and Electric Co.	Rob Collins	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	

6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Maryclaire Yatsko on behalf of SEminole Electric Cooperative)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Non-Binding Poll Results

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-03 GMD TPL-007-1
Poll Period:	11/12/2014 - 11/21/2014
Total # Opinions:	271
Total Ballot Pool:	344
Summary Results:	78.78% of those who registered to participate provided an opinion or an abstention; 69.67% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD's Mahmood Safi)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL Corporation NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe Seabrook,

				Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Comments submitted by Maryclaire Yatsko)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	California ISO	Rich Vine	Negative	COMMENT RECEIVED
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	

2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		

3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi - OPPD)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	

3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole

				Electric Cooperative Comments submitted by Maryclaire Yatsko)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - (DTE Electric)
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		

5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Abstain	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joseph Seabrook)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Maryclaire Yatsko)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	

6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (OG&E)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
6	PacifiCorp	Sandra L Shaffer		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiilates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Maryclaire Yatsko on behalf of Seminole

				Electric Cooperative)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bonneville Power Administration and Avista Utilities)
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert		

Individual or group. (58 Responses)
Name (35 Responses)
Organization (35 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Question 1 (49 Responses)
Question 1 Comments (58 Responses)
Question 2 (47 Responses)
Question 2 Comments (58 Responses)
Question 3 (40 Responses)
Question 3 Comments (58 Responses)
Question 4 (52 Responses)
Question 4 Comments (58 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type 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 and appropriate. On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads: “Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network

model.” Suggest adding the following paragraph afterwards: “Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model.” This comment was submitted during the last comment period.
Yes
Yes
The requirements and measures should be revised to allow Planning Coordinators to generally utilize consensus processes and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, the modeling data itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since those standards deal with load flow, stability, and short circuit data. Recommend that MOD-32 requirements R2 and R3 be added as requirements in the beginning of the GMD standard, but in R2 substitute the word “GMD” for “steady-state, dynamics, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. The Applicability section would have to be revised to include the additional entities. Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the 200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read “…wye-grounded winding with voltage terminals operated at 200kV or higher”. In Requirement R4 sub-Part 4.1.1. “System On-Peak Load” should be re-stated as “System On-Peak Load with the largest VAR consumption”. On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x α x β (in V/km). This indicates that the driving electrical field is in the Earth, and

not in the transmission wires. The wires do not create some kind of “antenna” effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections. This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.
Individual
Dr. Gabriel Recchia
University of Memphis
No
I would support a version of TPL-007-1 for which the statistical analyses were recomputed to take the considerations I mention in my responses to Question 4 into account, for which the numbers in TPL-007-1 Attachment 1 were adjusted accordingly, and for which the standards were adjusted to be appropriate given the new values.
Yes
In Appendix I of the Benchmark Geomagnetic Disturbance Event Description, I was concerned to see a decision to compute geoelectric field amplitude statistics that are averaged over a wide area. Appendix I of the Benchmark GMD Event Description currently states "The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales... Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below" (p. 9). However, to prepare for GMDs via the benchmark's current method (averaging over a square area of approximately 500 km in width) is similar to anticipating a 7.0 earthquake somewhere along the California coast, but preparing only for the average expected impact. Because the earthquake is only expected in one particular location, the average impact across the entire coast will be miniscule; if all

locations prepared only for the average impact, some would be woefully underprepared. In fact, the assumption is far worse than this earthquake analogy implies, because local failures in interconnected power systems can and do produce wide-area effects, as seen during the 1989 Hydro-Quebec blackout and the Northeast blackout of 2003*. Thus, analyses based on localized spatial scale estimates are precisely what is relevant, not wide-area spatial averages. I am also concerned that the extreme value analysis described does not take into account the fact that extreme space weather events follow a power law distribution (Lu & Hamilton, 1991; Riley, 2012). As stated by Riley (2012), "It is worth emphasizing that power laws fall off much less rapidly than the more often encountered Gaussian distribution. Thus, extreme events following a power law tend to occur far more frequently than we might intuitively expect" (see also Newman, 2005). Therefore it is likely that the analysis substantially underestimates the risk of high geoelectric field amplitudes. *Though not related to GMDs, the Northeast blackout of 2003 is nonetheless a good example of a local failure having wide-area effects. Lu, E. T., and R. J. Hamilton (1991), Avalanches and the distribution of solar flares, Astrophys. J., 380, L89–L92. Newman, M. (2005), Power laws, Pareto distributions and Zipf's law, Contemp. Phys., 46, 323–351. Riley, P. (2012), On the probability of occurrence of extreme space weather events, Space Weather, 10, S02012, doi:10.1029/2011SW000734.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
No
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. The drafting team continues to state that it is the responsibility of the owner to mitigate. 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 or the drafting team must clearly communicate how they envision the coordination between the PC/TP and the TO/GO occurring. TOs and GOs need to be involved in the development of the Corrective Action Plans that they will required to execute. The standard should require the PC to set up a stakeholder process with TOs and GOs related to these corrective action plans. The stakeholder process would take into account considerations such as scope of corrective action plans, schedules, market impacts, etc.
Yes
Yes
Yes
AEP remains concerned about the availability of the generic screening models. While the drafting team continues to publicize that the use of these models is an option for meeting the TO/GO requirements in R6, the drafting team has also stated that the development of the models is outside of their scope. In order to address uncertainty regarding these generic thermal models, AEP suggests that NERC commit to making industry-wide generic thermal models available as soon as possible, but no more than 18 months after NERC BOT approval of TPL-007-1. AEP supports the overall direction of this project, and envisions voting in the affirmative if the concerns provided in our response are sufficiently addressed in future revisions of TPL-007-1.
Individual
Thomas Lyons
Owensboro Municipal Utilities
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
No
This standard seems to place an undue burden on entities where there seems to be lack of adequate historical data to support.
Group
Dominion
Louis Slade
Yes

Yes
Yes
No
Individual
Terry Volkmann
Volkmann COnsulting
No
There is no technical justification to add an additional year to the process to an imminent problem.
No
There is no technical justification to add an additional year to the process to an imminent problem
Yes
Yes
The technical justification for spatial average of the 8V/km has not been adequately vetted among peers, the electric utility has not expertise in this average. In addition the SDT has not justified limiting the peak E-field area to only 100km. If it is 500km this is a huge area of the BES to allow a voltage collapse any outage.
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
No
(1) Seminole is confused as to whether the CP-3 value has been finalized by USGS or not, as USGS's website does not reflect the CP-3 value represented in the latest ballot. If the ground conductivity value for the Florida Peninsula, CP-3, is not final, i.e., USGS is still developing and researching the value, then the drafting team should delay vote on the Standard or allow for successive balloting on the final CP-3 value when USGS finalizes its value. Seminole does not believe the NERC Standards Process Manual allows for revisions to the CP-3 value after the Standard has been approved without re-opening the balloting. (2) Seminole is aware that a CEAP is not required to be performed, however, Seminole believes a CEAP is justified in this particular circumstance.
No
See Comments for #1 above and previous ballot Comments.

Individual
Bill Daugherty
Concerned citizen
No
The selection of the March 13-14 1989 GMD (Hydro Quebec) and the October 29-31 2003 Halloween events to define the 100 year GMD standards ignores a substantial body of work by researchers such as Bruce Tsurutani (NASA) and Daniel Baker (University of Colorado). NERC has chosen to define the 100 year GMD based solely on GMD events that were measured when CMEs actually hit the Earth in the 1980 to 2013 time frame. This ignores the work done by Tsurutani, Baker, and others that have quantified the magnitude of both pre 1980 events as well as events like the July 2013 event that was directed away from the Earth. The 1989 GMD was not all that strong when viewed on a historical basis, and the 2003 Halloween event, while a X17.2, resulted in a greatly dampened measured effect on the Earth's magnetic field since the magnetic component was pointing northward when it hit the Earth. Had it been pointing southward, the measured effect would have been greatly amplified. This 100 year GMD standard should not be allowed to be finalized without incorporating the findings and recommendations of papers like: Baker, D. N., X. Li, A. Pulkkinen, C. M. Ngwira, M. L. Mays, A. B. Galvin, and K. D. C. Simunac (2013), A major solar eruptive event in July 2012: Defining extreme space weather scenarios, Space Weather, 11, 585–591, doi:10.1002/swe.20097. and Tsurutani, B. T., and G. S. Lakhina (2014), An extreme coronal mass ejection and consequences for the magnetosphere and Earth, Geophys. Res. Lett., 41, doi:10.1002/2013GL058825 NERC has greatly underestimated the true magnitude of the 100 year threat to the electric grid from solar storms. This must be addressed before these standards are finalized.
No
Given the studies that I referenced in my response to Question 1, four years may be too long.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co.
Yes
Yes
Yes
Yes

For requirement 6 transformer assessment, we have a concern that the data required from the manufacturer of the transformer will not be available, especially for older units where the transformer manufacturer is no longer in business. From the 9/10/14 webinar, it is understood that screening models are in development, but there is no guarantee that they will be available to complete the assessment. Since we currently do not have any means at this time to complete this standard requirement, we will have to vote against approval of this standard.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
1.) Requirement 4.3 should have to be shared upon request only. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
No
1.) As many companies are going to be required to buy software and train for the specific modeling being required we recommend that this requirement have a 24 month implementation period. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Yes
We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Yes
Thank you for all of your work on this – this is not an easy one! We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. On some of even the most recent calls there still appears to be some lack of understanding as technical questions are asked. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. We recommend a pilot program. 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. If we pilot the process and shorten the implementation period then the final implementation of the solution could be the same with a much better effect. Please ask the question on the pilot even if the standard must move forward as is. Having the regions and NERC work through the process quickly with a few entities would still be very beneficial. Then all the other companies do not have to repeat the same mistakes to get where we really need to be. We also agree with the comments submitted by The Sacramento Municipal Utilities District (SMUD) for this standard.
Individual
John Merrell

Tacoma Power
Yes
Yes
Yes
No
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
No
Group
FirstEnergy Corp.
Richard Hoag
Yes
Yes
Increase from 4 to 5 years is an improvement
Yes
No
Individual
David Jendras
Ameren
No
We still strongly feel that a GMD event of 4-5 times the magnitude of the 1989 Quebec event as the basis for the 1 in 100 year storm is too severe, given the few “high magnitude” events that have occurred over the last 21 years, and therefore we believe that the

requirements to provide mitigation for these extreme GMD events are not supported. On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Minnesota as for Louisiana, while conservative, we believe would be absurd. Consideration with respect to unique geographical differences must be maintained among the functional entities to whom this standard would be applicable, particularly for PC's and their associated TP/TO entities.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
What is the estimated cost impact to entities for this activity, and what is the estimated marginal improvement in system reliability? We have heard from peers that the data requirements for a large system would take approximately 1 man-year to develop, and the source for this information is from a utility that has performed this activity per the draft standard. We are concerned given this significant investment in time and engineering resources, is there truly a need for a continent-wide standard when only select areas of the continent need to be concerned with GMD evaluation and mitigation? In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. We understand from representatives on the IEEE Transformer Committee that there are concerns that the 15 A threshold identified in the GIC standard is too low. We understand that the IEEE will be making a case to raise this threshold because the likelihood of transformer damage is small at that level of DC current (15 A) for the expected transient durations.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
The NSRF agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Yes

1. The NSRF agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. We suggest the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement: The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.
No
• The NSRF suggest the SDT change the VSL row for Requirement R6 to match the words in the standard. Suggestion: “The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months…” • The NSRF suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row. Suggestion: “The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Yes
• Page 9, Table 1 –Steady State Planning Events The NSRF suggest that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, we suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. • Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion: 4.2. Facilities: 4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. 4.2.1 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
Individual
Eric Bakie
Idaho Power
Yes
Yes
Yes

Yes
Idaho Power System Planning comments that additional clarity needs added to Table 1 regarding the GMD Event with Outages Category. It is unclear if planners have to include contingency conditions during a GMD event in the vulnerability assessment. If intent of the SDT is to require contingency analysis during a GMD Event to assess system performance; the required contingency categories (i.e. A or N-0, B or N-1, C or N-2) should be clearly identified in Table 1.
Group
SERC Planning Standards Subcommittee
David Greene
No
On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such a case, having the same geomagnetic scaling factor for Louisiana as for Minnesota, while conservative, would be absurd. Some sanity in this regard must be maintained among the functional entities to whom this standard would be applicable, particularly for PC’s and their associated TP/TO entities.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
In the GMD Planning Guide document, one reference noted on page 18 is the ‘Transformer Modeling Guide’ to be published by NERC. We are eager to see the contents of this document, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes. 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.
Group
SPP Standards Review Group
Robert Rhodes
No
5. Background – Replace ‘Misoperation’ with ‘Misoperation(s)’. R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 – set the phrase ‘as determined in Requirement R1’ off with commas. R4 – Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one

year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load. Rationale Box for Requirement R4 – Capitalize 'On-Peak' and 'Off-Peak'. Measure M5 – Insert 'in the Planning Area' between 'Owner' and 'that' in the next to last line of M5. Rationale Box for Requirement R5 – Capitalize 'Part 5.1' and 'Part 5.2'. Likewise, capitalize 'Part 5.1' under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section. R6/M6 – Capitalize 'Part 5.1'. Attachment 1 – We thank the drafting team for providing more clarity in the determination of the β scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Yes
Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requirements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
No
Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs. R5 – Capitalize 'Parts 5.1 and 5.2' in the High and Severe VSLs for Requirement R5. R6 – Capitalize 'Part 5.1' and 'Parts 6.1 through 6.4' in the VSLs for Requirement R6. R7 – Capitalize 'Parts 7.1 through 7.3' in the Moderate, High and Severe VSL for Requirment R7.
Yes
We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics – Capitalize 'Reactive Power' in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics – Replace 'Wide Area' in the 1st line of the 6th bullet under General Characteristics. The lower case 'wide-area' was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term 'Wide Area' refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don't believe the usage here is restricted to an RC's Wide Area view. The lower case'wide-area' is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude – In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the 'GIC system model'. In Requirement R2 of the standard a similar reference is made to the 'GIC System model' as well as 'System models'. In the later 'System' was capitalized. Should it be capitalized in this reference also? Statistical Considerations – In the 6th line of the 2nd

paragraph under Statistical Considerations, insert ‘the’ between ‘for’ and ‘Carrington’. Statistical Considerations – In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase ‘1 in 100 year’ is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as ‘1-in-100’. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification – In the 3rd line of the 1st paragraph under the Justification section, the phrase ’15 Amperes per phase neutral current’ appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as ’15 Amperes per phase’. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification – In the 2nd paragraph under the Justification section, the term ‘hot spot’ appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn’t. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification – In the 4th line of the Figure 4 paragraph, ’10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Individual
Terry Harbour
MidAmerican Energy Company
Yes
MidAmerican agrees with the changes made to TPL-007-1, however we do have concerns regarding the implementation plan and how it relates to the change in Requirement R6.4. We will also suggest additional changes to TPL-007-1 in our answers to the subsequent questions below.
Yes
MidAmerican agrees with the changes made to the implementation plan, but we are concerned that the 24-month deadline to prepare and provide the thermal impact assessment to the responsible entity in Requirement R6.4 will create a conflict with the initial performance of Requirement R6. If the TO and GO need the 48-month implementation plan, they cannot be compliant with Requirement R6.4. MidAmerican suggests the SDT add the following language to the proposed implementation plan: Initial Performance of Periodic Requirement The initial thermal impact assessment required byTPL-007-1, Requirement R6.4, must be completed on or before the effective date of the

standard. Subsequent thermal impact assessments shall be performed according to the timelines specified in TPL-007-1, Requirement R6.4.
No
MidAmerican suggest the SDT change the VSL row for Requirement R6 to match the words in the standard. Suggestion: “The responsible entity conducted a thermal impact assessment for its solely-owned and jointly-owned applicable Bulk Electric System power transformers where the maximum effective GIC value provided in Requirement R5 part 5.1 is 15 A or greater per phase but did so more than 24 calendar months…” MidAmerican suggest the SDT change the last paragraph in the VSL row for Requirement R6 to remove Requirement 6.4 because it is covered in the previous row. Suggestion: “The responsible entity failed to include one of the required elements as listed in Requirement R6 parts 6.1 through 6.3.
Yes
On Page 9, Table 1 – Steady State Planning Events MidAmerican suggests that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion, suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. Applicable Facilities: The applicability for TO and GO facilities do not match the language in Requirement R6.4. The reference to Bulk Electric System power transformers is not included in Section 4.2.1. Suggestion: Add 4.2.2 Facilities that include Bulk Electric System power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. Rationale for R2 Change “accounts for” to “includes” for clarity. Suggestion: The System model specified in Requirement R2 is used in conducting steady state power flow analysis that includes the Reactive Power absorption of transformers due to GIC in the System. Requirement R2 – General Comment Issues may arise in obtaining substation grounding and transformer DC resistance data two buses into neighboring utilities in a timely fashion. MidAmerican suggests some wording be included in Requirement R2 to address this issue, such as direction to share this data with neighboring utilities. Requirement R7 Add a space between R1 and “that”.
Individual
Karin Schweitzer
Texas Reliability Entity
No
1. Requirement R3: Texas Reliability Entity, Inc. (Texas RE) requests the SDT consider and respond to the concern that GMD criteria in the proposed standard for steady state voltage performance is different than the steady state voltage performance criteria in other TPL standards or the SOL methodology. GMD events will typically not be transient in nature so adopting the steady state approach is preferable as it would simplify the studies if the voltage criteria between GMD events and other planning events were the same. 2.

Requirement R7: Texas RE intends to vote negative on this proposed standard solely on the basis that we remain unconvinced that the proposed standard meets the intent of FERC Order 779. Paragraph 79 for the following reasons: (A) Reliance on the definition of Corrective Action Plans (CAP) in the NERC Glossary in lieu of including language in the requirement appears insufficient to address the FERC statement that a Reliability Standard require owners and operators of the BPS to "develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event." While Texas RE agrees that requiring the development of a CAP in Requirement R7 meets part of the FERC directive, R7 falls short as there is no language in the requirement (and therefore the standard) that addresses completion of the CAP. The CAP definition calls for an associated timetable but does not address completion. Coupled with the language in R7.2, that the CAP be reviewed in subsequent GMD Vulnerability Assessments, it is conceivable that a CAP may never get completed as timetables can be revised and extended as long as the deficiency is addressed in future Vulnerability Assessments. Without a completion requirement, a demonstrable reliability risk to the BES may persist in perpetuity. Texas RE recommends the SDT revise Requirement R7.2 as follows: "Be completed prior to the next GMD Vulnerability Assessments unless granted an extension by the Planning Coordinator." (B) The language in R7.1 does not appear to adequately address the FERC statement that "Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." While R7.1 lists examples of actions needed to achieve required System performance, it does not expressly restrict a CAP from only including revision of operating procedures or training. In addition, Table 1 language regarding planned system adjustments such as transmission configuration changes and redispatch of generation, or the reliance on manual load shed, seem to contradict the FERC language regarding the limiting plans to considering operational procedures. Texas RE suggests the revising the language of R7.1 as follows: "Corrective actions shall not be limited to considering operational procedures or enhanced training, but may include:" Alternatively, Texas RE suggests the addition of language to the Application Guidelines for Requirement R7 reinforcing FERC's concern that CAPs "must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." 3. Compliance Monitoring Process Section: Evidence Retention Texas RE remains concerned about the evidence retention period of five years for the entire standard. (A) Texas RE reiterates the recommendation that the CAP should be retained until it is completed. The SDT responded to Texas RE's first such recommendation with the following response: "The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not

believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance." With a periodic study period of five years, a CAP may extend significantly beyond the five-year window, especially in cases where equipment replacement or retrofit may be required. A retention period of five years could make it difficult to demonstrate compliance and could potentially place a burden on the entity as they will be asked 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. (B) Texas RE also recommends revising the evidence retention to cover the period of two GMDVAs. The limited evidence retention period has an impact on determination of VSLs, and therefore assessment of penalty. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained.
Yes
Yes
No
Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
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 that is applicable to the transformers to be evaluated. Without the curve(s), the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to affirmative 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.
Group

PPL NERC Registered Affiliates
Brent Ingebrigtson
No
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. The tools available for GOs and TOs to perform the transformer thermal impact assessments of TPL-007-1 requirement 6 are presently inadequate. There are two approaches for such work, as stated on p.4 of NERC's Transformer Thermal Impact Assessment White Paper: use of transformer manufacturer geomagnetically-induced current (GIC) capability curves, or thermal response simulation. We (and probably almost all entities) have no manufacturer GIC data, and the simulation approach requires, "measurements or calculations provided by transformer manufacturers," or, "conservative default values…e.g. those provided in [4]." Reference 4 includes only a few case histories and not widely-applicable transfer functions. Nor does there exist a compendium of, "generic published values," cited on p.9 of the White Paper. Performing thermal response experiments on in-service equipment is out of the question; so enacting TPL-007-1 in its present state would produce a torrent of requests for transformer OEMs to perform studies, this being the only available path forward. We anticipate that each such study would require several days of effort by the OEM and cost several thousand dollars, which would be impractical for addressing every applicable transformer in North America. Generic thermal transfer functions are needed, and the SDT representatives in the 9/3/14 teleconference with the NAGF standards review team agreed, adding that the Transformer Modeling Guide (listed as being "forthcoming" in NERC's Geomagnetic Disturbance Planning Guide of Dec. 2013) will become available prior to the time that GOs and TPs must perform their analyses. We have to base our vote regarding TPL-007-1 on the standard as it presently stands, however. We do not know whether or not the Transformer Modeling Guide will prove suitable, nor is there any guarantee that it will ever be published. We suggest that the standard be resubmitted for voting when all the supporting documentation is available. TPL-007-1 calls for PC/TPs to provide GIC time series data (R5), after which TO/GOs perform thermal assessments and suggest mitigating actions (R6). The PC/TPs then develop Corrective Action Plans (R7), which are not required to take into account the TO/GO-suggested actions and can include demands for, "installation, modification, retirement, or removal of transmission and generation facilities." The SDT representatives on the NAGF teleconference cited above stated that granting PC/TPs such sweeping powers over equipment owned by others is consistent with the precedent in TPL-001-4; but we disagree – TPL-001-4 is not even applicable to GOs and TOs. We have high regard for PC/TPs, and we agree that they should be involved in developing GMD solutions, but proposing to give them unilateral control over decisions potentially costing millions of dollars per unit is inequitable. This point is substantiated by the input from Dr. Marti of Hydro One (author of the reference #4 cited above) that they have never had to replace transformers for GMD mitigation; such actions as operational measures, comprehensive

monitoring, real time management and studies have been sufficient. R7of TPL-007-1 should be rewritten to require PC/TPs to reach agreement with GO/TOs regarding equipment modifications, replacements and the like.
Individual
David Thorne
Pepco Holdings Inc.
No
See Comments on items 2 and 4
No
: Screening models are not developed so this requirement puts the cart before the horse and the revised standard just proposes to move the due date out
Yes
Yes
The White papers are an attempt to explain the details but are not technically accurate. This is not a simple topic and much interpretation of the data is required. The response to GIC is related to the transformer ampere turns which determines the flux produced by the GIC. Increased flux increases the losses thus increasing temperatures. Without looking at the transformer design there is no way to be sure where the increase in flux or heating will create the hottest spot or where the heating will take place. Different transformers designs by different suppliers will react differently. A standard GIC profile curve with short duration peak and longer durations of GIC would allow a better delination of suspectable transformer designs rather than a hard number of 15 amperes per phase. Measurements of GIC and temperatures should be an allowable mitigation technique so the transformer response can be seen under many conditions and if needed the unit can be switched off line.
Group
Florida Municipal Power Agency
Carol Chinn
Yes
No
FMPA supports the comments of the FRCC GMD Task Force (copied below). The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an

implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of 'priliminary' with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force 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
FMPA does not agree with the SDT that failure to meet R4 or R7 could DIRECTLY cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures during a 1-in-100 year GMD event, and continues to believe the VRFs for these requirements should be lowered to medium.
Yes
FMPA supports the comments of the FRCC GMD Task Force (copied below). The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) 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 FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; "The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies." The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess

implementation timeframes and establish the appropriate levels of funding and the requisite resources.
Individual
John Bee on Behalf of Exelon and its Affiliates
Exelon
Yes
Yes
Yes
Yes
The Exelon affiliates would like to express concern with the reliance on transformer manufacturers to conduct the transformer thermal assessment identified in requirement 6. Specifically, our concern is that some transformer manufacturers may not be willing or able to perform the transformer thermal assessments or to provide the required data to conduct transformer thermal assessments in house. We understand that generic transformer models will be made available in the near future and that software tools will also be available to industry, which will utilize these generic transformer models that can be used should the transformer manufacturer be unable or unwilling to perform the thermal assessments. We believe that this approach could produce overly conservative results which may cause the implementation of mitigation measures that would otherwise be unnecessary if the transformer manufacturer data were used so that more accurate results would be achieved. At least one manufacturer has expressed concern that the use of generic models is incorrect because it does not take into account specific design parameters that only the manufacturers have access to. We also understand the implementation plan for TPL-007 will allow time for industry and the transformer manufacturers to work out the methodology and process associated with conducted transformer thermal assessments. Exelon would urge the transformer manufacturers and the NERC GMD Task Force come to a consensus and provide the necessary support and engagement with industry as well as groups supported by industry in developing transformer models and conducting transformer thermal assessments. We would ask that the Standard Drafting Team review the comments submitted by the transformer manufacturers and address them as appropriate.
Individual
Richard Vine
California ISO
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee

The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
The ISO supports comments submitted by the ISO/RTO Council Standards Review Committee
Individual
PHAN, Si Truc
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Hydro-Québec has the following concerns with the proposed standard: 1. The GMD Benchmark Event is too severe to be considered as normal event and should be used as a Extreme situation – the drafting team chose to maintain the 8v/Km value and considers that the 1/100 year should be equivalent to Category C and not Category D of current TPL standards. Hydro-Québec concurs with Manitoba Hydro's objection on this point. TPL-007 should follow a format with normal and extreme events, with different compliance requirements. A smaller scale GMD Benchmark Event should be considered as normal event. This is not a minority position, since both Manitoba and Québec's electric systems cover a non-negligible portion of Canada. 2. The GMD Benchmark Event is too preliminary to be applied on Hydro-Québec's system and enforce compliance : ♣ The study used statistical value of B and convert this into E. The conversion uses conservative hypothesis which provide approximation that do not reflect HQ's reality. The study consider, for an area of 200 km, a constant value of E which does not reflect a realistic situation for Hydro-Québec with a 1,000 km long system. The GMD Event should better take into consideration that the magnetic field and electric field are not constant (e.g. E=f(t)) nor uniform (e.g. E=f(x,y)) when studied on a large distance. It depends on time and location. ♣ The direct readings of E should be taken into consideration before retaining the GMD Benchmark Event. Some real measured E values exist and should be used to identify the GMC Event. ♣ The 5 to 8 V/Km is too high for the Hydro-Québec System. The highest global value observed is less than 3 V/Km. The frequency of the maximum local peak value have been observed for less than two minutes over a 167 month period. That could imply enormous investments on the system to comply to this theoretical GMD Event. 3. Even though the drafting team refers to different guides, it appears that the GMD Vulnerability Assessment is not clear enough. Concurring also with Manitoba comment no 4, the drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The harmonic analysis is missing in the standard. 4. At the 1989 event and after, Hydro-Quebec has not experienced any transformer damage due to GIC and have put strong efforts to test and

study GIC effect on Transformer. The 15 A criterion is too simplistic and does not take into account the real operating condition and type of transformer. The evaluation proposed in R6 causes a burden that is not relevant for utilities with high power transformers. 5. TPL-007-1 should be consistent with the philosophy applied in Standard PRC-006. In the latter standard, the TP must conduct an assessment when an islanding frequency deviation event occurs that did or should have initiated the UFLS operation. Similarly, if GMD actually causes an event on the system, then the TP or PC should simulate the event to ensure model adequacy (as per R2) and Assessment Review (as per R4) . 6. From a compliance perspective, there is no mention of what the Responsible entity as determined in R1 is supposed to do with the info provided by the TOs and GOs in R6.4. If the thermal impact assessments are supposed to be integrated in the GMD Vulnerability Assessment, it should be specified in R4. 7. The time sequence and delays are unclear regarding requirements R4, R5 and R6. Many interpretations are possible; the following is one example: a- GMD Vulnerability Assessment 1 (R4) b- GIC flow info (R5) c- Thermal impact assessment and report 24 months later d- Integration in GMD Vulnerability Assessment 2. Since assessments are performed about every 5 years, GMD Vulnerability Assessment 2 will only occur 3 years after reception of the thermal impact assessment? The DT should clarify the time sequence and delays between requirements R4, R5 and R6.
Individual
John Pearson/Matt Goldberg
ISO New England
Yes
No
We agree with extending the implementation plan to 60 months. However, more time for the development of the Corrective Action Plan under Requirement R7 should be provided within those 60 months. Once a Corrective Action Plan for one transformer is developed, the entity responsible for developing the Corrective Action Plan will have to run the model again to determine whether another Corrective Action Plan for other transformers is needed as a result of the first Corrective Action Plan. This step may have to be repeated several times. Thus, the time that the entities responsible for developing Corrective Action Plans have from the time they receive the results of the thermal impact assessments under Requirement R6 (which under the current timeline is only 12 months) is insufficient. Accordingly, we strongly suggest that the time for implementation of Requirement R6 be changed from 48 months to 42 months. The time for implementation for Requirement R7 would remain at 60 months but responsible entities would have 18 months to develop the Corrective Action Plans.
Yes
Yes

Section 4.2 in the Applicability section of the standard should be revised to state as follows: “Transformers with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” As the SDT explained in its answer to comments received on this section during the previous comment period, the standard applies only to transformers, so the words “[f]acilities that” at the beginning of the sentence are unnecessary and can lead to confusion. TPL-007 Requirement R2 should require rotation of the field to determine the worst field orientation. Without this explicit requirement, a Responsible Entity could miss important GMD impacts and, as a result, the standard may not achieve its stated purpose of “establish[ing] requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon.” If the Standard Drafting Team does not include this in Requirement R2, then at the least the Standard Drafting Team should include it in the Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System.
Group
Seattle City Light
Paul Haase
Yes
Yes
Seattle City Light is concerned with the effectiveness of the proposed approach (considerations of scientific and engineering understanding aside). Seattle is a medium-small vertically integrated utility, and like many such entities, is registered as a Planning Coordinator and Transmission Planner for our system and our system alone. And like many similar entities, we are closely connected with a large regional transmission utility (Bonneville Power Administration in our case). For this type of arrangement a GMD Vulnerability Assessment performed by Seattle (acting alone) on Seattle’s own system (considered alone) will be of little or no value. GMD assessments by other, similarly situated entities likewise will have little or no value. Recognizing the large number of such entities in WECC (something like half of the Planning Coordinators in all of NERC) and the Pacific Northwest, Seattle and others presently are coordinating with regional planning bodies in an effort to arrange some sort of common GMD Vulnerability Assessment that could promise results of real value across the local region. Aside from the usual difficulties attendant upon such an exercise in collaboration, the wording of Requirement R1 that assigns responsibility to Planning Coordinators individually introduces administrative compliance concerns that hinder coordination. Seattle asks that the Drafting Team consider alternative language for R1 (and Measure M1) that would more clearly allow, if not encourage, the possibility for local collaboration among Planning Coordinators. If such changes are not possible, a second best solution would be a paragraph in the guidance documentation stating that collaboration among Planning Coordinators is considered to be a means of meeting compliance with R1.

Individual
David Kiguel
David Kiguel
Yes
R4 provides for completion of Vulnerability Assessments once every 60 calendar months. As written, it could result in assessments performed as far appart as 120 months of each other if one is completed at the beginning of a 60-month period and the subsequent assessment is completed at the end of the following 60-month period. I suggest writing: once every 60 calendar months with no more than 90 months between the completion of two consecutive assessments. Considerable investment expenses could be necessary to comply with the proposed standard. As such, the standard should not proceed without a solid cost/benefit analysis to justify its adoption, especially considering the low frequency of occurrence of events (the frequency of occurrence of the proposed benchmark GMD event is estimated to be approximately 1 in 100 years). Given the low probability, moderate loss of non-consequential load could be acceptable.
Group
Duke Energy
Colby Bellville
Yes
No
Based upon our review of the Implementation Plan, it appears that the proposed timelines for some of the requirements (specifically R4 & R5) may not coincide properly. We request further explanation of the timelines, and their relationships between the various requirements.
Yes
No
Individual
Bill Fowler
City of Tallahassee
No
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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. 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 Standard Drafting Team (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.
Individual
Mahmood Safi
Omaha Public Power District
No
The Omaha Public Power District (OPPD) is concerned with language in "Table 1 - Steady State Planning Events" that requires entities to perform steady state planning assessments based on "Protection System operation or Misoperation due to harmonics during the GMD event". The Planning Application Guide's Sections 4.2 and 4.3 specifically mention the unavailability of tools and difficulty in performing an accurate harmonic assessment but does not provide resolution or recommendation on how to accurately address the concern. The statement from Section 4-3 is referenced below. "The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results." Additionally, there needs to be a clearer definition of how the steady state planning analysis due to GMD event harmonics is to be performed. Is it the intent of the standard to study the removal of all impacted Transmission Facilities and Reactive Power compensation devices simultaneously, sequentially, or individually as a result of Protection operation or Misoperation due to harmonics? The Planning Application Guide references the "NERC Transformer Modeling Guide" in several places as a reference for more information on how to perform the study.

The “NERC Transformer Modeling Guide” is shown in the citations as still forthcoming. OPPD doesn’t believe this standard should be approved prior to the industry seeing the aforementioned transformer modeling guide. Further, OPPD does not believe it is feasible to implement a full harmonic analysis in the implementation timeframe for TPL-007. In a very broad view, the standard requires a specific analysis that the industry doesn’t have the skill set or tools to perform. This is acknowledged by the supporting documents. The reference document cited as a resource to further explain how to perform the studies has not been created yet.
No
Please refer to comments in Question 1.
Yes
No
Individual
Mark Wilson
Independent Electricity System Operator
Yes
Yes
Yes
The IESO respectfully submits that the SDT has not provided guidance on achieving an acceptable level of confidence that mitigating actions are needed. To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed from service, we suggest that the SDT add a requirement that says “the TO and GO shall seek the PC’s and TP’s concurrence or approval of thermal analysis technique selection”. The IESO also concurs with Manitoba Hydro and Hydro –Quebec comment that the SDT has not provided guidance on what are acceptable assumptions to make when determining which facilities should be removed as a result of a GMD event. The IESO respectfully reiterates our suggestion to amend the planning process to achieve an acceptable level of confidence as follows: 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.
Group

Con Edison, Inc.
Kelly Dash
No
The Drafting Team has to consider and address the fact that there are Transmission Owners that maintain extensive underground pipe-type transmission systems in which the shielding impact of the surrounding pipe infrastructure around the cables is not taken into account by Attachment 1 or any current modeling software. The Drafting Team is again being requested to address shielded underground pipe-type transmission lines, instead of only addressing the unshielded buried cables discussed in their prior responses to comments. Because of this, application of the current draft of the standard is problematic for Transmission Owners with shielded underground pipe-type transmission feeders. The standard fails to differentiate between overhead transmission lines and shielded underground pipe-type transmission feeders. While overhead transmission lines and unshielded buried cables may be subject to the direct above ground influences of a Geomagnetic Disturbance (GMD), shielded underground pipe-type feeders are not. The ground and the pipe shielding of a shielded underground pipe-type transmission line attenuate the impacts of any GMD event. Recommend that the equation in Attachment 1 have an additional scale factor to account for all shielded underground pipe-type 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 and appropriate. On page 25 of the document Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013 in the section Transmission Line Models which begins on page 24, it reads: “Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network model.” Suggest adding the following paragraph afterwards: “Pipe-type underground feeders are typically composed of an oil-filled steel pipe surrounding the three-phase AC transmission conductors. The steel pipe effectively shields the conductors from any changes in magnetic field density, B [16](Ref. MIL-STD-188-125-1). So, pipe-type underground feeders that fully shield the contained three-phase AC transmission conductors are not to be included as a GIC source in the transmission line model. Pipe-type underground feeders that partially shield the contained three-phase AC transmission conductors are to be included as a fractional GIC source (using a multiplier less than 1) in the transmission line model.” This comment was submitted during the last comment period.
Yes
FAC-003 avoids using the phrase “terminal voltage” by using the phrase “operated at 200kV or higher.” Facilities 4.2.1 reads: “Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.” Terminal voltage implies line to ground voltage (200kV line-to-ground equates to 345kV line-to-line). Is the

200kV line-to-ground voltage what is intended? Line-to-line voltages are used throughout the NERC standards. Suggest revising the wording to read "…wye-grounded winding with voltage terminals operated at 200kV or higher". On page 2 of the Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System December 2013, Figure 1 (entitled GIC flow in a simplified power system) is misleading. The driving voltage source for geomagnetically induced currents or GICs are generated in the Earth between the two grounds depicted on Figure 1. The Vinduced symbols should be removed from the individual transmission lines and one Vinduced (the driving Earth voltage source) should instead be placed between and connected to the two ground symbols at the bottom of Figure 1. The grounded wye transformers and interconnecting transmission lines between those two grounds collectively form a return current circuit pathway for those Earth-generated GICs. Equation (1) in the Attachment 1 to the TPL-007-1 standard states that Epeak = 8 x α x β (in V/km). This indicates that the driving electrical field is in the Earth, and not in the transmission wires. The wires do not create some kind of "antenna" effect, especially in shielded pipe-type underground transmission lines. That is, the transmission wires depicted in Figure 1 are not assumed to pick-up induced currents directly from the magnetic disturbance occurring in the upper atmosphere, something like a one-turn secondary in a giant transformer. Rather, they merely form a return-current circuit pathway for currents induced in the Earth between the ground connections. This also suggests that Figure 21 on page 25 (entitled Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations) is also misleading or incorrectly depicted. The Vdc driving DC voltage source is in the Earth between the grounds, not the transmission lines. The Vac currents in the (transformer windings and) transmission lines are additive to Earth induced Vdc currents associated with the GMD event flowing in these return-current circuit pathways. Figure 21 should show Vdc between the grounds, while Vac should be located in the (transformer windings and) transmission lines between the same grounds. If the impedance of the parallel lines (and transformer windings) is close, which is likely, you may assume that one-third of the GIC-related DC current flows on each phase. Any other figures with similar oversimplifications should also be changed to avoid confusion.
Group
Associated Electric Cooperative, Inc.
Phil Hart
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
Group
IRC SRC
Greg Campoli
No
1. The ISO/RTO Standards Review Committee (SRC) respectfully submits that the modifications to the measure remove the ability of Planning Coordinators to vet and implement protocols that are broadly applicable to Transmission Planners in its footprint through a consensus process. The requirement to develop individual protocols in coordination with each and every Transmission Planner individually creates unnecessary and unduly burdensome administrative processes that lack a corresponding benefit. The requirement and measure should be modified to allow Planning Coordinators to utilize consensus processes generally and engage with individual entities (Transmission Planners, etc.) when necessary to address issues specific to that entity. Additionally, th SRC notes that the modeling data itself will need to come from the applicable Transmission Owner and Generator Owner. Reliability standards such as MOD-032 wouldn't apply here, since that standard deals with load flow, stability, and short circuit data. Accordingly, the SRC recommends that requirements R2 and R3 from MOD-032 be added as requirements in the beginning of the GMD standard and substitute the word “GMD” where it states “steady-state, dynamic, and short circuit”. These additional requirements that include these additional entities will ensure that the data needed to conduct the studies is provided. These additional requirements would have the same implementation time frame as R1. In addition to adding the requirements noted above, the below revisions are proposed: R1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall delineate the individual and joint responsibilities of the Planning Coordinator and these entities in the Planning Coordinator’s planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). [Violation Risk Factor: Low] [Time Horizon: Long-term Planning] M1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall

provide documentation on roles and responsibilities, such as meeting minutes, agreements, and copies of procedures or protocols in effect that identifies that an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1. Corresponding revisions to VSLs are also recommended. 2. The SRC notes that the use of the term “Responsible Entities” “as determined under Requirement R1” is ambiguous and could be modified to be more clearly stated. The below revisions are proposed: “Entities assigned the responsibility under Requirement R1” Corresponding revisions for associated measures and VSLs are also recommended. 3. The SRC respectfully reiterates its comment 2 above regarding the term “Responsible Entities” “as determined under Requirement R1” and recommends that, for all instances where “Responsible Entity” is utilized in Requirement R3, similar revisions are incorporated. Corresponding revisions for associated measures and VSLs are also recommended. 4. The SRC respectfully reiterates its comment 3 above for all instances where “Responsible Entity” is utilized in Requirement R4. It further notes that Requirement R4 is ambiguous as written. More specifically, the second sentence could more clearly state expectations. The following revisions are proposed: R4. Entities assigned the responsibility under Requirement R1 shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use studies based on models identified in Requirement R2, include documentation of study assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] Corresponding revisions for associated measures and VSLs are also recommended. 5. The SRC respectfully reiterates its comment 3 above for all instances where “Responsible Entity” is utilized in Requirement R5. Additionally, for Requirement R5, no timeframe is denoted for provision of the requested data. To ensure that requested or necessary data is provided timely such that it can be incorporated in the thermal assessment required pursuant to Requirement R6. It is recommended that the requirement be revised to include a statement that the data is provided by a mutually agreeable time. Corresponding revisions for associated measures and VSLs are also recommended. 6. The SRC respectfully submits that, as written, Requirement R6 appears to require an individual analysis and associated documentation for each power transformer and does not allow Transmission Owners and Generator Owners to gain efficiencies by producing a global assessment and set of documentation that includes all required equipment. It further does not allow these entities to collaborate and coordinate on the performance of jointly-owned equipment, creating unnecessary administrative burden and reducing the exchange of information that could better inform analyses. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 15 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal

impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5; 6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and 6.4. 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. Corresponding revisions for associated measures and VSLs are also recommended. 7. As a global comment, the confidentiality of the information exchanged pursuant to the standard should be evaluated and, if necessary, the phrase “subject to confidentiality agreements or requirements” inserted in Requirements R3 through R7. Corresponding revisions for associated measures and VSLs are also recommended.
No
Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised.
No
1. Requirement R1 is a purely administrative requirement and, while important to ensure that all requirements are fully satisfied, should not be assigned a “Severe” VSL. A Moderate VSL is proposed. 2. Requirement R3 is a purely administrative requirement and, while important to ensure that system performance criteria are documented and understood, should not be assigned a “Severe” VSL. A Moderate VSL is proposed. 3. The VSL assigned to Requirement R2 penalizes the responsible entity for not maintaining “System model”, which is already a requirement in MOD-032-1, R1. Assuming “GIC System model” includes “DC Network models” the VSL language assigned to Requirement R2 should be modified as follows: “The responsible entity did not maintain GIC System models of the responsible entity’s planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).”
Yes
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. Specifically, Table 1 provides: “Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event” However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess “Misoperation due to harmonics”. The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked. The SRC respectfully notes that this standard is unlike other NERC standards. While the SRC understands that the scope and assignment of the drafting team was to develop

standards to implement mitigation of GMD events, the industry has little experience in the matter and, as a result, the proposed standard is a composition of requirements for having procedures and documentation of how an entity performs a GIC analysis for GMD, which essentially makes the overall standard administrative in nature. The SRC would submit to the SDT that this is not the best use of resources and, as these comments point out, are quite removed from direct impacts on reliability. At a minimum, none of the requirements within this standard deserve High VSL ratings. In fact, it is highly probable that, if these requirements were already in effect today, they would be clear candidates for retirement under FERC Paragraph 81. While SRC understands that these requirements are the most effective way to address GMD risk at this time, the compliance resources involved to meet these requirements need to be considered on an ongoing basis and future efforts must be made to evolve the standard into more performance and result-based requirements, which would facilitate the retirement of the procedural/administrative requirements that currently comprise this standard.
Individual
Scott Langston
City of Tallahassee
No
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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics. 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 Standard Drafting Team (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.
Group

FRCC GMD Task Force
Peter A. Heidrich
No
The FRCC GMD Task Force thanks the SDT and NERC staff for their cooperative efforts with the USGS in establishing a preliminary earth model for Florida (CP3), and the corresponding scaling factor. However, the preliminary earth model and scaling factor are still lacking the necessary technical justification and the FRCC GMD Task Force is reluctant to support an implementation plan that is based on the expectation that the USGS will develop a final earth model for Florida with the necessary technical justification that supports an appropriate scaling factor. Therefore, the FRCC GMD Task Force recommends that the implementation plan be modified to allow the FRCC region to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS can validate an appropriate scaling factor for peninsular Florida. In accordance with the above concern, the FRCC GMD Task Force requests that the implementation of all of the Requirements be delayed for peninsular Florida, pending finalization (removal of ‘priliminary’ with sufficient technical justification) of the regional resistivity models by the USGS. In the alternative, the FRCC GMD Task Force requests that Requirements R3 through R7 at a minimum be delayed as discussed, as the scaling factor is a prerequisite for those Requirements. If the second option is chosen, the FRCC GMD Task Force 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.
Yes
The FRCC GMD Task Force continues to request that the Standard Drafting Team (SDT) apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC GMD Task Force requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The FRCC GMD Task Force is disappointed by the SDTs reposnse to this request during the initial posting period which states in part; “The drafting team has approached cost considerations in a manner that is consistent with other reliability standards by providing latitude to responsible entities. The SDT recognizes that there is a cost associated with conducting

GMD studies. However, based on SDT experience GMD studies can be undertaken for a reasonable cost in relation to other planning studies.” The FRCC GMD Task Force believes that the past practice of addressing cost considerations during previous standard development projects and specifically this project are inadequate in providing the industry with the necessary cost information to properly assess implementation timeframes and establish the appropriate levels of funding and the requisite resources. It has become very apparent that the SDT and NERC staff are unwilling to analyze the cost for implementation of this Standard, therefore, the FRCC GMD Task Force continues to request 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 GMD Task Force 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, which can be provided upon request.
Individual
Jo-Anne Ross
Manitoba Hydro
No
Note “System steady state voltages shall…” was removed from Table 1, which removes the link back to requirement R3. Note d should be re-established and the language similar to that used in TPL-001-4 should be considered: “System steady state and post-Contingency voltage performance shall be within the criteria established by the Planning Coordinator and the Transmission Planner.”
Yes
Yes
Yes
Manitoba Hydro has five main concerns with the proposed standard: 1. GMD Benchmark Event is too severe - We have made comments previously that we disagree with making a 1/100 year event equivalent to a “Category C” event (as defined in the current TPL standards) in terms of performance requirements. Comments have been made by the drafting team that this is a minority position. Manitoba Hydro’s objections are: a) A 1/100 year event “Category D” event is not mandated in Order 779. The FERC Order 779 states “… of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events a responsible entity

must assess for potential impacts on the Bulk-Power System.” b) Manitoba Hydro does not want this to be precedent setting for opening up a review of the extreme events in the current TPL standards and raising the bar for these disturbances in the future. The Transmission Owner should be in the best position to judge their level of risk exposure to extreme events in terms of benefits vs. costs. 2. Thermal Assessments not necessary - We have made recommendations to remove the transformer thermal assessments from TPL-007; specifically remove requirements, R5 and R6. The reason is based on: a) these requirements being burdonesome on utilities in northern latitudes, Transformer thermal assessments should be limited to transformers that have a confirmed wide area impact to minimize the assessment burden. b) these requirements are based on science that is still evolving, The drafting team is still in the process of finalizing the thermal impact assessment whitepaper. This supporting document should be finalized prior to recommending mandatory standards. c) these requirements having limited reliability benefits, Currently, requirement R6.3 only requires the development of suggested actions. There is no requirement to implement the suggested actions. If no actions are mandated then why is the analysis required? Rather than using a 15 A per phase metric, perhaps R4.4 and R4.5 from TPL-001-4 could be used for guidance where the Planning Coordinator identifies the transformers that are lost or damaged are expected to produce more severe System impacts (eg Cascading) as well as an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence. Such an approach would limit the number of transformers requiring assessment to a manageable number. d) these requirements are not mandated in Order 779. Order 779 does not clearly mention that transformer thermal assessments are required. However, one of the FERC Order 779 requirements implies that a thermal assessment should be done: “If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event.” Damage to critical or vulnerable BPS equipment implies damage due to thermal stress. FERC 779 requires testing for instability, uncontrolled separation or cascading as a result of damage to a transformer or transformers. The TPL-007 standard as drafted does not require an assessment of the impacts of potential loss of a several transformers due to excessive hot spot temperature. Presumably, the hot spot temperature would not coincide to the 8 V/km peak of the benchmark GMD event. The drafting team should specify at what level of GMD (eg 1 V/km) it might be expected that transformers would trip due to hot spot temperature. 3. The TPL-007 standard does not address all of FERC Order 779 - as drafted TPL-007 does not include an assessment of the impacts of equipment lost due to damange that result in instability, uncontrolled separation or cascading failures on the BPS. FERC Order 779 states, “If the assessments identify potential impacts from the benchmark GMD events, the reliability standard should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation or cascading failures of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, as a result of a benchmark GMD event.” Instead it appears that the TPL-007 approach may

(R6.3 is not worded clearly as to whether or not mitigation is required) require that all elements impacted by thermal heating get mitigated independ of whether or not their loss results in instability, uncontrolled separation or cascading failures on the BPS. Requiring mitigation on elements for which their loss does not result in instability, uncontrolled separation or cascading failures may result in unnecessary costs with no reliability benefits. 4. Harmonic Analysis is missing -The drafting team has not provided guidance on what are acceptable assumptions to make when determining which reactive facilities should be removed as a result of a GMD event. The approach proposed in the current standard probably wouldn't have prevented the 1989 Hydro Quebec event. The 1989 event was a lesser event (compared to the 1-in-100 year benchmark event) in which system MVAR losses as a result of GIC were relatively insignificant and transformer thermal heat impacts were negligible. The 1989 black out occurred due to protection mis-operations tripping of SVCs due to harmonics, which then triggered the voltage collapse. Unfortunately harmonic analysis tools, other than full electromagnetic transient simulation of the entire network, have not been developed to date. A suggestion is to at minimum require an assessment to identify a list of equipment which when lost due to GIC would result in instability, uncontrolled separation or cascading failures on the BPS. For example this would require the tripping of all reactive power devices (shunt capacitors) connected to a common bus. Equipment (such as SVCs and shunt capacitors) that have been checked to ensure protection neutral unbalance protection is unlikely to misoperate or that are immune to tripping due to harmonic distortion would be exempt (equipment may still trip due to phase current overload during periods of extreme harmonics. However, this is expected to be a local single bus or local area phenomena as opposed to region wide issue like in the Quebec 1989 event). 5. GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC's of 24.5 Amps and 20.2 Amps. Analysis of the EPRI SUNBURST GIC data also indicates that the ALL peak GIC values between 10 Amps to 24 Amps were measured in NERC's supposed geoelectric field cut-off zone (between 40 to 60 degrees geomagnetic latitude).
Individual
Karen Webb
City of Tallahassee
No
Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: 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 Standard Drafting Team (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.
Yes
Yes
Yes
It seems that parameters involved with GMD events and associated GIC’s are still being widely studied and disputed. It would be prudent to submit the “Benchmark GMD Event Data” for a peer review of experts based in the area of Space Science/Physics. Quoting from the previous Unofficial Comment Form Project 2013-03 - Geomagnetic Disturbance Mitigation: 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 Standard Drafting Team (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.
Group
JEA
Tom McElhinney
JEA supports the comments of the FRCC GMD Task Force.
Group
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana
Erica Esche
Yes
Vectren proposes the SDT to consider a different approach to the Applicability and/or registered functions identified in R1. Consider modifying the Applicability section of TPL-007-1 to mirror CIP-014’s Applicability section; ‘Transmission Facilities that are operating … 200 kV and … above at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an ‘aggregated weighted value’ exceeding ### according the to the table (table to be created by SDT or to use the same from CIP-014). To identify the greatest

threat to the Bulk Electric System (BES), the SDT could revise Requirement R1's responsible registered functions to only the Planning Coordinator. Vectren believes the PC performing a system-wide assessment would be of greater value to the BES over including entities with less of an overall reliability impact to the BES. Data to perform the assessment is provided to the Planning Coordinator as part of existing MOD, FAC, and PRC standards.
Individual
Bill Temple
Northeast Utilities
Yes
Yes
Yes
Yes
It appears that the way Requirement 7.3 of the proposed standard is written presents the potential for competition conflicts under FERC Order 1000. Can the SDT provide feedback to the industry as to what, if any, impact evaluation was done on this requirement as it may impact FERC Order 1000.
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We would like to thank the SDT for already addressing many of our concerns regarding the previous drafts of this standard. However, we still have a concern regarding how the applicable entities are identified in this standard and recommend the SDT designate the Planning Coordinator as the applicable entity for compliance with Requirement R1. R1 lists both the PC and the TP as concurrently responsible for compliance, 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, should be the entity responsible for performing the GMD Vulnerability Assessment. The SDT identifies their justification for this approach is the same as the one taken in other planning standards, and while we appreciate an effort to maintain consistency between standards, this approach has forced many entities to plan and implement formal coordination agreements between PCs and TPs on a regional basis to identify the responsibilities of conducting these assessments. The approach spreads the burden of compliance among many entities rather than directly assigning the responsibilities to just a smaller set, the Planning Coordinators. We believe the SDT should remove each reference to "Responsible entities as determined in Requirement R1" and instead properly assign the PC. (2) We appreciate the SDT providing their justifications for a facility criterion with the applicability of this standard;

however, we believe the SDT should remove this criterion and instead utilize the current BES definition that went into effect on July 1, 2014. Like the SDT, we also acknowledge that parts of the proposed standard apply to non-BES facilities and that some models need such information to accurately calculate geomagnetically-induced currents. However, that criterion should be identified within the Guidelines and Technical Basis portion of the standard. Adding the facility criterion upfront in the applicability section of the standard provides confusion to both industry and auditors when 200 kV high-side transformers may apply. The BES definition identifies all Transmission Elements operated at 100 kV or higher and accounts for inclusions and exclusions to that general definition. The SDT should leverage the technical analysis that was performed to achieve industry consensus and FERC approval for the revised BES definition. The current approach only provides additional confusion.
No
We appreciate the SDT's recognition that the previous implementation plan identified for this standard was too short and burdensome for entities. More time and information need to be made available for entities to properly construct the necessary data models and conduct these new studies correctly. Entities have also received limited assistance with their vendors on the provision of the data necessary to conduct these studies. Large and small entities have limited resources, software, and industry knowledge in this area. Moreover, for smaller entities with limited staff and financial resources, this effort will be a significant challenge. We continue to recommend that the implementation period be extended to eight years to allow industry an opportunity to fully engage in this effort.
No
We appreciate the SDT's efforts to identify measureable criteria for many of the VSLs identified in this standard. However, we continue to disagree with the SDT's assignment of VRFs for this standard. The SDT identifies that they have aligned the VRFs with the criteria established by NERC. However, we want to remind the SDT of the planning horizon identified in this standard and not to confuse the nature of the event with insufficient or unsupported GMD Vulnerability and thermal impact assessments. We disagree with the categorization of Medium VRFs for the applicable requirements because these requirements could not "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System." While the nature of the event could affect the electrical state or capability of the BES, we believe not maintaining system models or identifying performance criteria for acceptable system steady state voltage limits would have no affect on the electrical state or capability of the BES.
No
(1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. Thank you for the opportunity to comment.
Individual
Sonya Green-Sumpter

South Carolina Electric & Gas
No
On page 10 of 24 of the redline version of the revised draft standard, it is stated that the geomagnetic scaling factor to be selected should be the most conservative over the planning area footprint. However, while individual TP/TO footprints may not cover a large span of possible scaling factors, PC footprints likely would. In such having the same geomagnetic scaling factor for a footprint that covers a wide variety of latitudes and bedrock conditions. The individual the applicable entities should be allowed to use judgment in applying the scaling factors.
Yes
We appreciate the additional time allocated for the various activities encompassed by this draft standard.
Yes
Yes
In the GMD Planning Guide document, one reference noted on page 18 is the 'Transformer Modeling Guide' to be published by NERC. This document has not yet been distributed and, particularly in regards to quantifying the link between the quasi-DC GIC currents which would flow and additional transformer reactive power absorption that this would represent in the AC system model to be used for assessment purposes, it would be useful to have the opportunity to review it.
Individual
Anthony Jablonski
ReliabiltiyFirst
Yes
ReliabilityFirst votes in the Affirmative and believes the TPL-007-1 standard enhances reliability and establishes requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events. ReliabilityFirst offers the following comments for consideration 1. Requirement R7 - During the last comment period ReliabilityFirst provided a comment on Requirement R7 which suggested that R7 should require the Entity to not only develop a Corrective Action Plan but "Implement" it as well. The SDT responded with "CAP must include a timetable for implementation as defined in the NERC Glossary". Even though the NERC definition of CAP implies that an entity needs to implement the CAP, ReliabilityFirst does not believe it goes far enough from a compliance perspective. ReliabilityFirst also notes that other NERC/FERC approved standards (PRC-004-2.1a R1 - "…shall develop and implement a Corrective Action Plan to avoid future Misoperations…" and PRC-004-3 – R6 "Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5…") require entities to "Implement the CAP" so ReliabilityFirst believes it is appropriate to in include this language. ReliabilityFirst offers the following language for consideration: "Responsible entities as determined in Requirement R1that conclude through the GMD Vulnerability

Assessment conducted in Requirement R4 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall:”
Individual
Brett Holland
Kansas City Power and Light
No
5. Background – Replace ‘Misoperation’ with ‘Misoperation(s)’. R2/M2, R3/M3, R4/M4, R5/M5 and R7/M7 – set the phrase ‘as determined in Requirement R1’ off with commas. R4 – Requirement R4 requires studies for On-Peak and Off-Peak conditions for at least one year during the Near Term Planning Horizon. Does this mean a single On-Peak study and a single Off-Peak study during the 5-year horizon? What is the intent of the drafting team? Would the language in Parts 4.1.1 and 4.1.2 be clearer if the drafting team used peak load in lieu of On-Peak load. The latter is a broader term which covers more operating hours and load scenarios than peak load. Rationale Box for Requirement R4 – Capitalize ‘On-Peak’ and ‘Off-Peak’. Measure M5 – Insert ‘in the Planning Area’ between ‘Owner’ and ‘that’ in the next to last line of M5. Rationale Box for Requirement R5 – Capitalize ‘Part 5.1’ and ‘Part 5.2’. Likewise, capitalize ‘Part 5.1’ under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis section. R6/M6 – Capitalize ‘Part 5.1’. Attachment 1 – We thank the drafting for providing more clarity in the determination of the β scaling factor for larger planning areas which may cross over multiple scaling factor zones. Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs.
Yes
Again, we thank the drafting team for their consideration in lengthening the implementation timing for all the requiements in this standard. This standard addresses new science and it will take the industry time to adequately transition to the new requirements.
No
Generic – When referring to calendar days, calendar months, etc., please hyphenate the preceeding number of days such as in 90-calendar days (R4/M4/VSLs & R7/M7), 24-calendar months (R6/M6) and other lengths of time as appear in the VSLs. R5 – Capitalize ‘Parts 5.1 and 5.2’ in the High and Severe VSLs for Requirement R5. R6 – Capitalize ‘Part 5.1’ and ‘Parts 6.1 through 6.4’ in the VSLs for Requirement R6. R7 – Capitalize ‘Parts 7.1 through 7.3’ in the Moderate, High and Severe VSL for Requirment R7.
Yes

We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. Benchmark Geomagnetic Disturbance Event Description General Characteristics – Capitalize ‘Reactive Power’ in the 2nd line of the 3rd bullet under General Characteristics. General Characteristics – Replace ‘Wide Area’ in the 1st line of the 6th bullet under General Characteristics. The lower case ‘wide-area’ was used in the Rationale Box for R6 in the standard and is more appropriate here as well. The capitalized term ‘Wide Area’ refers to the Reliability Coordinator Area and the area within neighboring Reliability Coordinator Areas which give the RC his wide-area overview. We don’t believe the usage here is restricted to an RC’s Wide Area view. The lower case’wide-area’ is used in the paragraph immediately under Figure I-1 under Statistical Considerations. Reference Geoelectric Field Amplitude – In the line immediately above the Epeak equation in the Reference Geoelectric Field Amplitude section, reference is made to the ‘GIC system model’. In Requirement R2 of the standard a similar reference is made to the ‘GIC System model’ as well as ‘System models’. In the later ‘System’ was capitalized. Should it be capitalized in this reference also? Statistical Considerations – In the 6th line of the 2nd paragraph under Statistical Considerations, insert ‘the’ between ‘for’ and ‘Carrington’. Statistical Considerations – In the 1st line of the 3rd paragraph under Statistical Considerations, the phrase ‘1 in 100 year’ is used without hyphens. In the last line of the paragraph immediately preceeding this paragraph the phrase appears with hyphens as ‘1-in-100’. Be consistent with the usage of this phrase. Screening Criterion for Transformer Thermal Impact Assessment Justification – In the 3rd line of the 1st paragraph under the Justification section, the phrase ’15 Amperes per phase neutral current’ appears. In the 6th line of the paragraph above this phrase under Summary, the phrase appears as ’15 Amperes per phase’. All other usages of this term, in the standard and other documentation, have been the latter. Are the two the same? If not, what is the difference? Was the use of the different phrases intentional here? If so, please explain why. Additionally, the phrase appears in Requirements R5 and R6 as 15 A per phase. In the last paragraph under Requirement R5 in the Application Guidelines, Guidelines and Technical Basis, the phrase appears as 15 amps per phase. Whether the drafting team uses 15 Amperes per phase, 15 A per phase or 15 amps per phase, please be consistent throughout the standard and all associated documentation. Justification – In the 2nd paragraph under the Justification section, the term ‘hot spot’ appears several times. None of them are hyphenated. Yet in Table 1 immediately following this paragraph, the term is used but hyphenated. Also, in the Background section of the standard, the term is hyphenated. The term also can be found in the Benchmark Geomagnetic Disturbance Event Description document. Sometimes it is hyphenated and sometimes it isn’t. Whichever, usage is correct (We believe the hyphenated version is correct.), please be consistent with its usage throughout all the documentation. Justification – In the 4th line of the Figure 4 paragraph, ’10 A/phase’ appears. Given the comment above, we recommend the drafting team use the same formatting here as decided for 15 Amperes per phase.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.

Yes
Although Tri-State appreciates the intent of the language change in R3, we believe it's now ambiguous as to what is meant by "performance." What did the SDT have in mind with that change? How does the SDT imagine this to be audited? Tri-State believes there is an error in Attachment 1 of the standard. On page 11 under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use the largest Beta factor of physiographic regions or a technically justified value." However on page 22 of the GMD Benchmark White Paper under "Scaling the Geoelectric Field" it reads: "When a ground conductivity model is not available the planning entity should use a Beta Factor of 1 or other technically justified value." These should be consistent and the Attachment in the standard should read as it does in the Benchmark White Paper. There is language already stating that the largest Beta Factor of 1 should be used in cases where entities have large planning areas that span more than one physiographic region.
Yes
Yes
Yes
On page 11 of the "Transformer Thermal Impact Assessment" White Paper it states "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." We are interested to know what is meant by "measured"? Does this have to be done in the lab or can this be done through monitoring of existing transformers?
Group
Iberdrola USA
John allen
Yes
Yes
Yes
Yes
Direction on the scope of reactive devices to be removed in the standard's Table 1 should be provided. This would include number of devices and/or % within a geographic proximity. It is not clear whether all devices or only specified devices should be removed from service.
Individual
Catherine Wesley
PJM Interconnection
Yes

Yes
Yes
No
Individual
Gul Khan
Oncor Electric
Yes
Yes
Yes
No
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
We’d like to express our gratitude and acknowledge the SDT efforts in preparing this standard. We wish to encourage the standard drafting team to consider the flexibility for entities to meet the Requirement R1 through including regional planning groups or something equivalent in Requirement R1. This would allow an entity’s participation in such planning groups to meet the terms of the requirement while providing a consistent study approach within a regional boundary. We believe this change meets FERC’s intent while alleviating entities duplication of studies while providing a consistent approach on the regional basis. R1. Each Planning Coordinator “or regional planning group”, in conjunction with each of its Transmission Planners, shall identify the individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator’s planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). Thank you. Joe Tarantino, PE
Group
Bonneville Power Administration
Andrea Jessup

Yes
Yes
Yes
Yes
BPA notes that presently commercial study software does not have the functionality to evaluate the impact of GIC on a transformer; it needs to be capable of this in order to appropriately apply the screening criteria for the complexity of analyzing flows through a transmission network via a benchmark storm. The most significant need is for autotransformers as the core is exposed to an “effective current” influence for the actual flux saturation level which is from an additive or subtractive coupling of current flow in the common and series winding. BPA reiterates our question from the previous comment period: 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.
Group
Foundation for Resilient Societies
William R. Harris
No
COMMENTS OF THE FOUNDATION FOR RESILIENT SOCIETIES (Comment 1 of 2 submitted 10-10-2014) TO THE STANDARD DRAFTING TEAM NERC PROJECT 2013-03 – STANDARD TPL-007-1 TRANSMISSI0N SYSTEM PLANNED PERFORMANCE FOR GEOMAGNETIC DISTURBANCE EVENTS October 10, 2014 Answer to Question 1: No, we do not agree with these specific revisions to TPL-007-1. Detailed responses are below. Requirement R3 should contain steady state voltage “limits” instead of the subjective term “performance.” Measure M3 should contain steady state voltage “limits” instead of the subjective term “performance.” Table 1, “Steady State Planning Events” has been changed to allow “Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service” as primary means to achieve BES performance requirements during studied GMD conditions. When cost-effective hardware blocking devices can be installed, load loss should not be allowed. Protective devices that keep geomagnetic induced currents (GICs) from entering the bulk transmission system extend service life of other critical equipment, allow equipment to “operate through” solar storms, reduce reactive power costs and support higher capacity utilization. In contrast, load shedding while GSU transformers remain in operation tend to reduce equipment life and continue to allow GICs into the bulk power system, risking grid instabilities. Capacitive GIC blocking devices are, to first order, insensitive to uncertainties in GMD currents and thus protect the grid against a large range of severe GMD environments. Table 1, “Steady State Planning Events” has been changed to allow Interruption of Firm Transmission Service and Load Loss due to “misoperation due to

harmonics." When cost-effective hardware blocking devices can be installed, misoperation due to harmonics should be prevented. On page 12, text has been changed to "For large planning areas that span more than one β scaling factor from Table 3, the most conservative (largest) value for β should may be used in determining the peak geoelectric field to obtain conservative results." "May" is not a requirement; the verb "should" needs to be retained in the standard. Under "Application Guidelines," Requirement R6 now reads: "Transformers are exempt from the thermal impact assessment requirement if the maximum effective GIC in the transformer is less than 15 Amperes per phase as determined by a GIC analysis of the System. Justification for this screening criterion is provided in the Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding the maximum effective GIC value provided in Requirement R5 Part 5.2 is also a justifiable threshold criterion that exempts a transformer from Requirement R6." These exemptions from the assessment requirements of this standard, both singly and in combination, defeat a key purpose of FERC Order No. 779, which is to protect the bulk power system from severe geomagnetic disturbances: (1) By failing to require the utilization of now-deployed and future-deployed GIC monitors, of which there were at least 102 in the U.S. in August 2014 (see Resilient Societies' Additional Facts filing, Aug 18, 2014, FERC Docket RM14-01-000), and now at least 104 GIC monitors, NERC fails to mandate use and data sharing from actual GIC readings, and cross-monitor corroboration of regional GIC levels. This systematic failure to use available risk and safety-related data may enable "low-ball modeling" of projected GIC levels both at sites with GIC monitors and at other regional critical facilities within GIC monitoring; (2) The so-called "benchmark model" developed by NERC significantly under-projects GICs and electric fields. The Standard Drafting Team, in violation of ANSI standards and NERC's own standards process manual, has failed to address on their merits, or refute with scientific data and analysis, the empirically-backed assertions of John Kappenman and William Radasky in their White Paper submitted to the Standard Drafting Team of NERC on July 30, 2014. See also the Resilient Societies' "Additional Facts" filing in FERC Docket RM14-01-000, dated Aug. 18, 2014. Using a smaller region of Finland and the Baltics as a modeling foundation, the NERC Benchmark model under-estimates geoelectric fields by factors of 1.5. To 1.9. This systematic under-estimation of geoelectric fields will have the effect of excluding entities that should be subject to the assessment requirements, thereby reducing the analytic foundation for purchase of cost-effective hardware protective equipment thus allowing sizable portions of the grid to be directly debilitated, with cascading effects on other portions of the grid. (3) In the NERC Standard Drafting Team's review of the Kappenman-Radasky White Paper submitted on July 30, 2014, the STD Notes claim: "They [the Standard Drafting Team] did not agree with the calculated e-fields presented in the commenter's white paper for the USGS ground model and found that the commentator's result understated peaks by a factor of 1.5 to 1.9" Meeting Notes, Standard Drafting Team meeting, August 19 [20014] Comment Review, page 2, para 2b, at page 3. This is altogether garbled. The commenters, using empirical data from solar storms in the U.S. and not in Finland, found the benchmark model understated GICs and volts per kilometer by a factor of 1.5 to 1.9. The Standard Drafting Team has submitted the standard to a subsequent ballot without addressing the Kappenman-Radasky White Paper critique on its merits. This is a violation of both ANSI standards and the NERC standards process manual requirements. (4) To exempt mandatory assessments if a transformer manufacturer's design specifications claim transformer withstand tolerances above the benchmark-projected amps per phase is to place grid reliability upon a foundation of quicksand. (A) Manufacturers generally do not test high voltage transformers to destruction, so their certifications of equipment tolerances are scientifically suspect; (B) As the JASON Summer study report of 2011, declassified in December 2011, indicates: a review of the warranties included with most high voltage transformer sales contracts exclude liability for transformer failures due to solar weather, so "transformer ratings" are not guaranteed and are not backed by financial reimbursement for equipment losses or resulting loss of business claims. The JASONs concluded it was more prudent to purchase neutral ground blocking devices than to pay to test extra high voltage transformers and still risk equipment loss in severe solar weather; (C) The claims of transformer manufacturers have been disputed by national experts, so without testing by a neutral third party, such as a DOE national energy laboratory, these claims are suspect, and should not, without validated third party testing, be an allowable exclusion from mandatory assessment by all responsible entities. See, for example, the Storm Analysis Consultants Report Storm R-112, addressing various unsubstantiated claims by ABB for various transformers. Storm-R-112 noted a number of ABB claims that could not be substantiated. Moreover, in transformer ratings provided to American Electric Power, Kappenman asserts that manufacturer reports have failed to address the most vulnerable winding on the transformer, the tertiary winding. John Kappenman informed the Standard Drafting Team that measurable GIC withstand was much lower than what the manufacturer had estimated for one tested transformer. He further explains that tests carried out by manufacturers only have been able to go up to about 30 amps per phase and were set up to actually exclude or inhibit looking at the most vulnerable tertiary winding on tested transformers. Papers submitted to IEEE and CIGRE discuss these tests but ignore the tertiary winding vulnerabilities. Hence these nonrigorous, manufacturer-biased "ratings" should not, without third party validation, exempt an entity from assessment responsibilities under this standard. (5) The submission of comments today, October 10, 2014, by John Kappenman and Curtis Birnbach, further invalidates the NERC Benchmark model as a basis to design vulnerability assessments. Both the alpha factor and the beta factor of the NERC model significantly under-project GICs and geoelectric field of anticipated quasi-DC currents. The so-called "benchmark" standard is not ready for prime time. If the Standard Drafting Team fails to address the systematic biases in its modeling effort, if it fails to utilize U.S. data and not Finland and Baltic region data, if it fails to require modeling based on the full set of 104 GIC monitors and future added GIC monitors, NERC will be in violation of its ANSI obligations and in violation of the standard validation process set forth in NERC's own Standards Process Manual adopted in June 2013. (6) Resilient Societies reported to the GMD Task Force as far back as January 2012 that vibrational impacts of GICs were the proximate cause of a 12.2 day outage of the Phase A 345 kV three-phase transformer at Seabrook Station, New Hampshire on November 8-10, 1998. Magnetostriction and other vibrations of critical

equipment are associated with moderate solar storms. A moderate North-South/South-North reversing solar storm caused ejection of a 4 inch stainless steel bolt into the winding of the Phase A transformer at Seabrook, captured by FLIR imaging as the transformer melted on November 10, 1998. NERC’s own compilations on the March 1989 Hydro-Quebec storm records contain dozens of separate reports of vibration, humming, clanging, and other audible transformer noise at locations within the U.S. electric grid at the time that the GSU transformer at Salem Unit 1 melted. More recently, tests at Idaho National Laboratory in 2012, reported by INL and SARA in scientific papers in 2013, confirm that GICs injected into 138 kV transmission lines cause adverse vibrational effects; and that neutral blocking devices eliminate these vibrational effects. It is arbitrary and capricious for the NERC Standard Drafting Team to fail to address vibrational effects of GMD events, and vibrational elimination when neutral ground blocking equipment is installed. Even if the Standard Drafting Team would prefer a standard that discourages any obligation to install neutral ground blocking devices, such an outcome does not comply with ANSI standards. Evidence-based standards are needed. Excluding an entire category of risks (magnetostriction and other vibrations) that are well documented in literature on vibrational risks in electric grids should be unacceptable to NERC, to FERC, and to ANSI. (7) The Standards Drafting Team did not act to address our comments submitted on July 30, 2014, in violation of ANSI requirements that comments be addressed. Areas not addressed include, but are not limited to: (A) No adjustment for e-field scaling factors at the edge of water bodies. (B) No standard requirement for the assessment of mechanical vibration impacts. (C) No requirement for testing of transformers to validate thermal and mechanical vibration withstand when subjected to DC current limits. (8) Our concerns with NERC’s speculative “hot spot” conjecture for GIC impacts over wide areas were not addressed. Under separate cover to NERC, we are submitting data and analysis that shows NERC’s “hot spot” conjecture is inconsistent with real-world data. In conclusion, we note that the Federal Energy Regulatory Commission in its Order No. 779 [143 FERC ¶ 61,147, May 16, 2013) ordered “that any benchmark events proposed by NERC have a strong technical basis.” Emphasis added, quoting Order No. 779 at page 54. For the above reasons, among others, NERC’s draft standard TPL-007-1 does not presently have a “technical basis” for its implementation, let alone a “strong technical basis” as required by FERC’s Order.
Yes
With a 60 month implementaiton period, it would be highly beneficial to utilize and require data sharing for the 104 or more GIC monitors now operational in the United States. See Foundation's "Additional Facts" filing in FERC Docket RM14-1-000 of Aug 18, 2014. A model using all the GIC monitors operating now or in the future would enable more cost-effective operating procedures and hardware protection decisions.
Yes
Yes
The Foundation for Resilient Societies submits these Comment 1 of 2, and separately. A second comment submitted on Oct 10 2014 involves graphics for concurrent GIC spikes at

near-simultaneous times hundreds or even thousands of miles apart. These findings refute the unsubstantiated "GIC Hotspot" model used to average down the effective GIC levels. This bias, combines with the alpha modeling bias (See Kappenman-Radasky White Paper submitted on July 30, 2014) and the beta modeling bias (See Kappenman-Birnbach comments 10-10-2014) in combination result in the NERC GMD Benchmark Model under-estimating overall geoelectric fields and risks to critical equipment by as high as one order of magnitude. Unless corrected, cost-effective purchases of protective equipment will be needlessly discouraged, and the grid will remain at needless risk. ANSI standards and NERC's standards process manual require addressing flaws and criticisms on their merit. This has not been done!
Group
PacifiCorp
Sandra Shaffer
No
Please refer to the response for #4.
Yes
Yes
PacifiCorp is voting no on this ballot to reflect our concerns (a) that insufficient evidence has been presented to show that the potential impact of a geomagnetic disturbance is significant for the majority of the North American electrical grid, and (b) that the effort that will be required to fully comply with this standard as drafted is not commensurate with the risk. However, PacifiCorp would support this effort if the initial implementation was limited to areas with the highest levels of perceived risk such as areas, for example, above 50 degrees of geomagnetic latitude and within 1000 kilometers of the Atlantic or Pacific coasts. Based on this approach, methods and tools used for the assessment can be further developed while addressing those areas most at risk. PacifiCorp’s concerns can be summarized as follows: (1) The SDT had not provided adequate evidence to show that the impacts of Geomagnetic disturbance are significant at lower latitudes. (2) The at-risk areas for impacts on the transmission system due to Geomagnetic disturbance are limited. The SDT should consider applying this standard only to utilities above 60° geomagnetic latitude until adequate data and evidence is available to show lower latitude utilities are impacted to the same degree as higher latitude utilities. (3) In cases where an assessment is deemed necessary, the SDT should consider adding a specific provision where the utilities will be allowed to use prior cycle study results unless a stronger solar storm has been detected than the test signal or significant changes have occurred in the transmission system. Such a provision will reduce the burden on utilities and their customers.
Individual
Wayne Guttormson
SaskPower

Yes
1. GMD Benchmark Event appears to be an extreme event - Making a 1/100 year event equivalent to a “Category C” event in terms of BES performance does not seem supported. 2. Thermal Assessments do not seem to be supported. In general, transformer thermal assessments should be limited to transformers that have a confirmed wide area impact. a) the science is still evolving, b) reliability benefits seem limited,& c) not mandated in Order 779.

Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1
Submitted to NERC on October 10, 2014

Executive Summary

The NERC Standard Drafting Team has proposed a Benchmark GMD Event based on a 1-in-100 year scenario that does not stand up to scrutiny, as data from just three storms in the last 40 years greatly exceed the peak thresholds proposed in this 100 Year NERC Draft Standard. The Standard Drafting Team then developed a model to estimate Peak Electric Fields (Peak E-Field) at locations within the continental United States for use by electric utilities that also has not been validated and appears to be in error. In these comments technical deficiencies are exposed in both the Benchmark GMD Event and the NERC E-Field model. These deficiencies include:

1. The NERC Benchmark GMD Event was developed using a data set from geomagnetic storm observations in Finland, not the United States.

2. The NERC Benchmark GMD Event was developed using a data set from a time period which excluded the three largest storms in the modern era of digital observations and does not include historically large storms.

3. The NERC Benchmark GMD Event excludes consideration of data recorded during geomagnetic storms in the United States in 1989, 1982, and 1972 that show the NERC benchmark is significantly lower than real-world observations.

4. While it is well-recognized that Peak dB/dt from geomagnetic storms vary according to latitude, observed real-world data from the United States shows that the NERC latitude scaling factors are too low at all latitudes. For storms observed over a 100 year period, NERC latitude scaling factors would be significantly more in error.

5. While it is well-recognized that Peak Electric Fields from geomagnetic storms vary according to regional ground conditions, observed real-world data from the United States shows that the NERC geo-electric field simulation models are producing results that are too low and may have embedded numerical inaccuracies.

6. When the estimated E-Field from the NERC model is compared to E-Field derived from measured data at Tillamook, Oregon during the Oct 30, 2003 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 5.

7. When the estimated E-Field from the NERC model is compared to the E-Field derived from measured data at Chester, Maine during the May 4, 1998 storm, the estimated E-Field from the NERC model is too low by a factor of approximately 2.

8. The errors noted in points 5 and 6 become compounded when combined to determine the NERC Epeak levels for any location. The erroneous NERC latitude scaling factor, and the erroneous NERC geo-electric field model are multiplied together which compounds the errors in each part and produces an enormous escalation in overall error. In the case of Tillamook, it produces results too low by a factor of 30 when compared with measured data.

9. The NERC Benchmark GMD Event, NERC latitude scaling factors, and the NERC geo-electric field model do not use available data from over 100 Geomagnetically-Induced Current monitoring locations within the United States.

In conclusion, the NERC Standard has been defectively drafted because the Standard Drafting Team has chosen to use data from outside the United States and which excludes important storm events to develop its models instead of better and more complete data from within the United States or over more important storm events. GIC data in particular is in the possession of electric utilities and EPRI but not disclosed or utilized by NERC for standard-setting and independent scientific study. The resulting NERC models are systemically biased toward a geomagnetic storm threat that is far lower than has been actually observed and could have the effect of exempting United States electric utilities taking appropriate and prudent mitigation actions against geomagnetic storm threats.

The circumstances presented by this NERC standard development process are extraordinarily unusual, to say the least. Any other credible standards development organization that has ever existed would want to take into consideration all available data and observations and perform a rigorous as possible examination to guide their findings, fully test and validate simulation models etc. Yet this NERC Standards Development Team has decided to not even bother to gather and look at enormously important and abundant GIC data and develop useful interpretations and guidance that this data would provide. NERC has also refused to gather known data on other transformer failures or recent power system incidents that might be associated with geomagnetic storm activity. NERC has developed findings and standards that are entirely based upon untested and un-validated models, models which have also been called into question. These models further put forward results that in various ways actually contradict and ignore the laws of physics. The NERC Standard Development Team behavior parallels to an agency responsible for public safety like the NTSB refusing to look at airplane black box recorder data or to visit and inspect the crash evidence before making their recommendations for public safety. Such behaviors would not merit public trust in their findings.

Discussion of Inadequate Reference Field Storm Peak Intensity and Geomagnetic Field Scaling Factors

As Daniel Baker and John Kappenman had noted in their previously submitted comments in May 2014, there have been a number of observations of geomagnetic storm peaks higher than those in the NERC proposed in TPL-007-1 Reference Field Geomagnetic Disturbance[1]. The purpose of this filing is to further elaborate upon the NERC Draft Standard inadequacies and to also propose a new framework for the GMD Standard.

It is the role of Design Standards above all other factors to protect society from the consequences possible from severe geomagnetic storm events, this includes not only widespread blackout, but also widespread permanent damage to key assets such as transformers and generators which will be needed to provide for rapid post-storm recovery. It is clear that the North American power grid has experienced an unchecked increase in vulnerability to geomagnetic storms over many decades from growth of this infrastructure and inattention to the nature of this threat. In order for the standard to counter these potential threats, the standard must accurately define the extremes of storm intensity and geographic

[1] Daniel Baker & John Kappenman "Comments on NERC Draft GMD Standard TPL-007-1 – Problems with NERC Reference Disturbance and Comparison with More Severe Recent Storm Event", filed with NERC for Draft Standard TPL-007-1, May 2014

footprint of these disturbances. It is only then that the Standard would provide any measure of public assurance of grid security and resilience to these threats.

It is clear from the prior comments provided by a number of commenters that the NERC TPL-007-1 Draft Standard was not adequate to define a 1 in 100 year storm scenario and was not conservative as the NERC Standards Drafting Team claims. Further the NERC Standards Drafting team has not proceeded in their deliberations and developments of new draft standards per ANSI requirements. In developing the Draft 3 Standard now to be voted on and prior drafts, the Standard Drafting Team did not address multiple comments laying out technical deficiencies in the NERC storm scenario. According to the ANSI standard-setting process, comments regarding technical deficiencies in the standard must be specifically addressed.

Figure 1 provides a graphic illustration of the NERC Standard proposed geomagnetic field intensity in nT/min, adapted from Table II-1 of α "Alpha" scaling of the geomagnetic field versus latitude across North America[2].

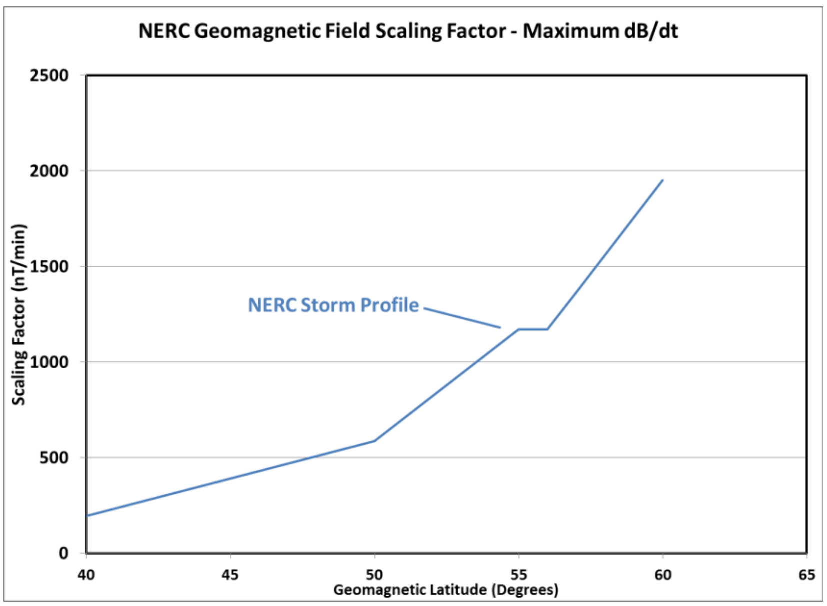

Figure 1 - NERC Proposed Profile of Geomagnetic Disturbance Intensity versus Geomagnetic Latitude

NERC has developed the intensity and profile described in Figure 1 from statistical studies carried out using recent data from the Image Magnetic observatories located in Finland and other Baltic locations[3]. This data base is a very small subset of observations of geomagnetic storm events, it is limited in time and does not include the largest storms of the modern digital data era and is limited in geography as it only focuses on a very small geographic territory at very high latitudes. The lowest latitude observatory in the Image array is at a geomagnetic latitude approximately equivalent to the US-Canada border, so this data set would not be able to explore the profile at geomagnetic latitudes below 55° and therefore reliably characterize the profile across the bulk of the US power grid. The NERC Reference Field excludes the possibility of a Peak disturbance intensity of greater than 1950 nT/min and further excludes that the peak could occur at geomagnetic latitudes lower than 60°. As observation data and other scientific analysis will show, both of these NERC exclusions are in error.

[2] Page 20 of NERC Benchmark Geomagnetic Disturbance Event Description, April 21, 2014.

[3] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

For the NERC Reference profile of Figure 1 to be considered a conservative or 1 in 100 year reference profile, then no recent observational data from storms should ever exceed the profile line boundaries. However as previously noted, the statistical data used by NERC excluded world observations from the large and important March 1989 storm and also from two other important storms that took place in July 1982 and August 1972, a time period that only covers the last ~40 years. In addition, data developed from analysis of older and larger storms such as the May 1921 storm have been excluded by NERC in the development of this reference profile. In just examining the additional three storms of August 4, 1972, July 13-14, 1982, and March 13-14, 1989, a number of observations of intense dB/dt can be cited which exceed the NERC profile thresholds. Figure 2 provides a summary of these observed dB/dt intensities and geomagnetic latitude locations that exceed the NERC reference profile.

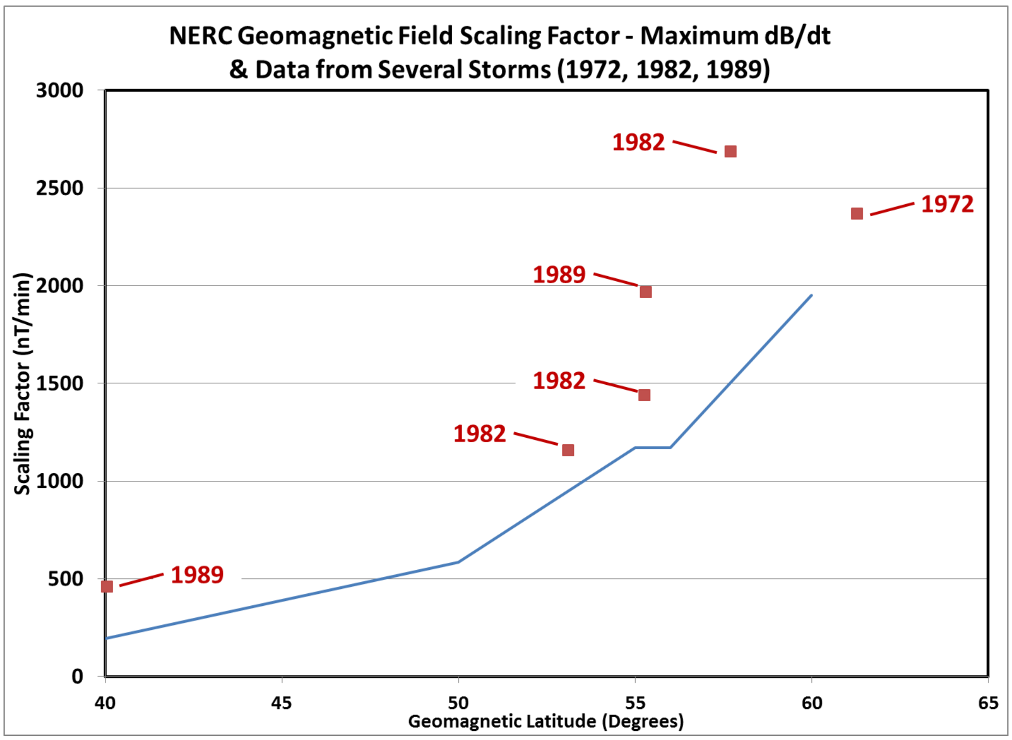

Figure 2 – NERC 100 Year Storm Reference Profile and Observations od dB/dt in 1972, 1982 and 1989 Storms that exceed the NERC Reference Profile

As Figure 2 illustrates that are a number of observations that greatly exceed the NERC reference profile at all geomagnetic latitudes in just these three storms alone. The geomagnetic storm process in part is driven by ionospheric electrojet current enhancements which expand to lower latitudes for more severe storms. The NERC Reference profile precludes that reality by confining the most extreme portion of the storm environment to a 60^{o} latitude with sharp falloffs further south. This NERC profile will not agree with the reality of the most extreme storm events. The excursions above the NERC profile boundary as displayed in Figure 2 clearly points out these contradictions.

In terms of what this implies for the North American region, a series of figures have been developed to illustrate the NERC reference field levels at various latitudes and actual observations that exceed the NERC reference thresholds. Figure 3 provides a plot showing via a red line the ~55^{o} geomagnetic latitude across North America which extends approximately across the US/Canada border. Along this boundary, the NERC Reference profile sets the Peak disturbance threshold at 1170 nT/min, but when considering the three storms not included in the NERC statistics database, it is clear that peaks of ~2700 nT/min have been observed at these high latitudes over just the past ~40 years. As will be discussed later, it is also understood that extremes up to ~5000 nT/min can occur down to these latitudes. Figure 4 provides a similar map showing the boundary at 53^{o} geomagnetic latitude across the US and per the NERC Reference profile, the peak threat level would be limited to 936 nT/min. Yet at this same latitude at the Camp Douglas Station geomagnetic observatory, a peak dB/dt of ~1200 nT/min was observed during the July 1982 storm. Figure 5 provides a map showing the boundary at 40^{o} geomagnetic latitudes and the NERC Reference peak at this location of only 195 nT/min. This figure also notes that in the March 1989 storm the Bay St. Louis observatory observed a peak dB/dt of 460 nT/min, this is 235% larger than the NERC peak threshold.

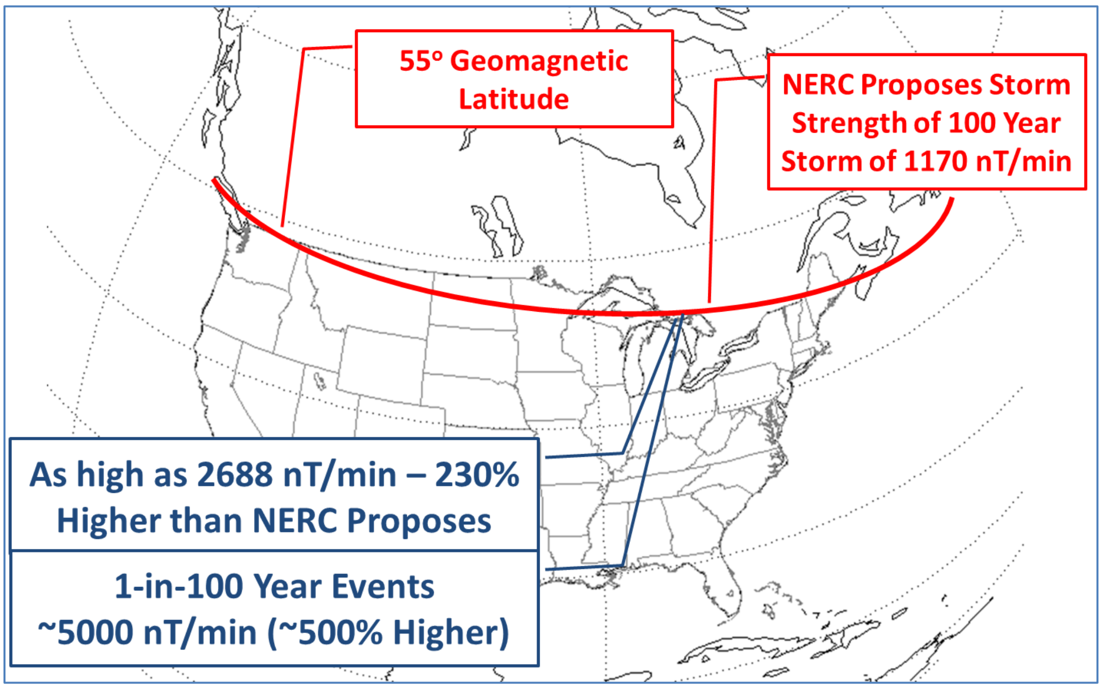

Figure 3 – Comparison of NERC Peak at 55^{o} Latitude versus Actual Observed dB/dt

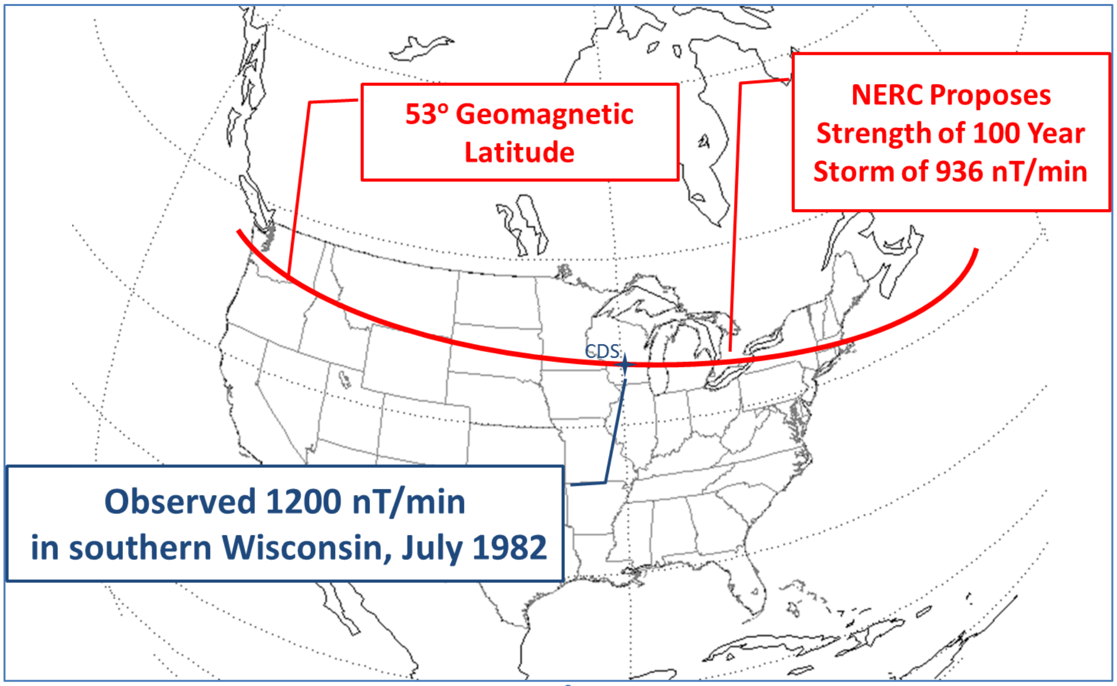

Figure 4 - Comparison of NERC Peak at 53° Latitude versus Actual Observed dB/dt

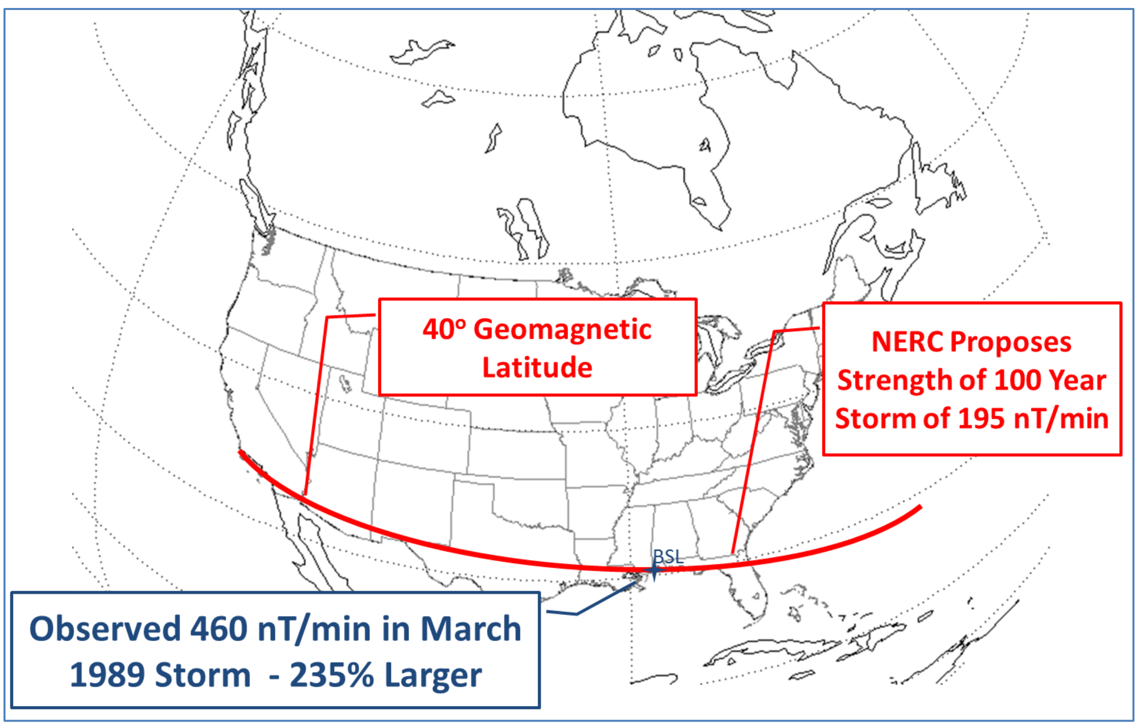

Figure 5 - Comparison of NERC Peak at 40° Latitude versus Actual Observed dB/dt

In summary, these storm observations limited to just three specific storms which happen to fall outside the NERC statistical database all show observations which exceed the NERC Reference profile at all latitudes. This illustrates that the NERC Reference profile cannot be a 1 in 100 year storm reference waveform and is not conservative. It should also be noted that even these three storm events are not representative of the worst case scenarios. In an analysis limited to European geomagnetic observatories, a science team publication concludes "there is a marked maximum in estimated extreme

levels between about 53 and 62 degrees north" and that "horizontal field changes may reach 1000-4000 nT/minute, in one magnetic storm once every 100 years"[4]. One advantage of this European analysis, it did not exclude data from older storms like the March 1989 and July 1982 storms, unlike in the case of the NERC database statistical analysis. In another publication the data from the May 1921 storm is assessed with the following findings; "In extreme scenarios available data suggests that disturbance levels as high as ~5000 nT/min may have occurred during the great geomagnetic storm of May 1921"[5]. In another recent publication, the authors conclude the following in regards to the lower latitude expansion of peak disturbance intensity; "It has been established that the latitude threshold boundary is located at about 50–55 of MLAT"[6]. It should be noted that one of the co-authors of this paper is also a member of the NERC Standards drafting team. All of these assessments are in general agreement and all call into question the NERC Reference Profile. Figure 6 provides a comparison plot of these published results with respect to the NERC Draft Standard profile and illustrates the significant degree of inadequacy the NERC Reference profile provides compared to these estimates of 100 Year storm extremes.

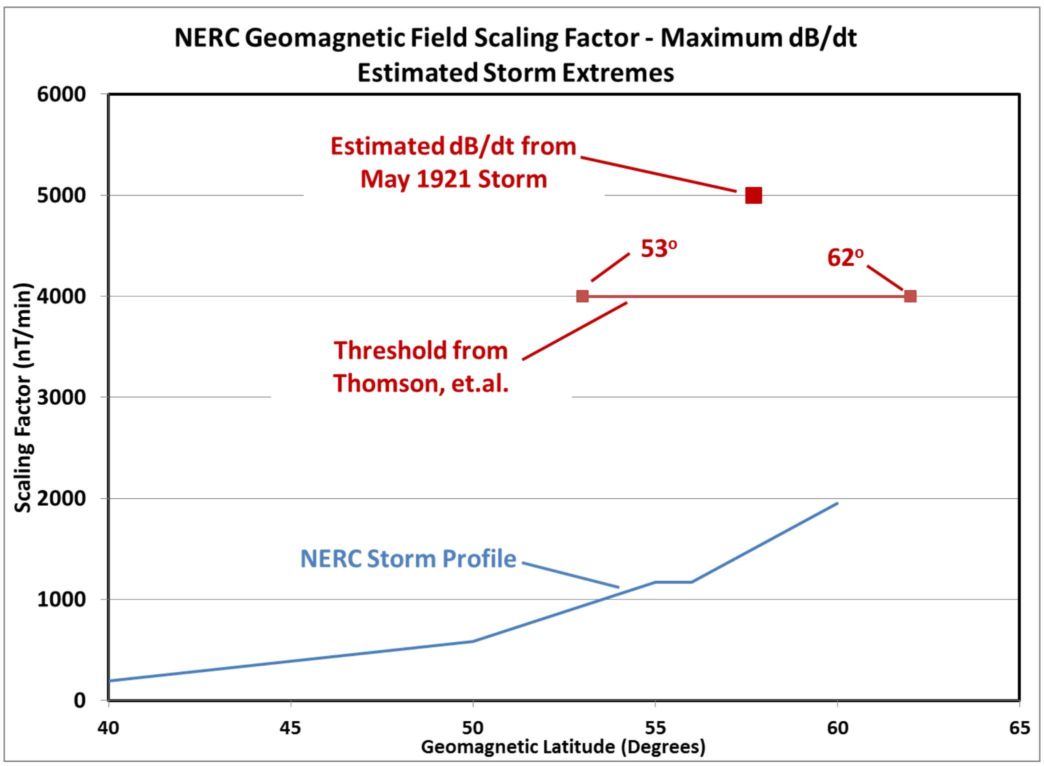

Figure 6 – Scientific Estimates of Extreme Geomagnetic Storm Thresholds compared to Propose3d NERC Draft Standard Profile

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[4] Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, Space Weather, 9, S10001, doi:10.1029/2011SW000696, 2011.

[5] John G. Kappenman, Great Geomagnetic Storms and Extreme Impulsive Geomagnetic Field Disturbance Events – An Analysis of Observational Evidence including the Great Storm of May 1921, Advances in Space Research, August 2005 doi:10.1016/j.asr.2005.08.055

[6] Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, Space Weather, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013.

Discussion of Inadequate Geo-Electric Field Peak Intensity

As the prior section of this discussion illustrates, the Peak Intensity of the proposed NERC geomagnetic disturbance reference field greatly understates a 100 year storm event. In prior comments submitted, it was also discovered that the geo-electric field models that NERC has proposed will also understate the peak geo-electric field[7]. In developing the Peak Geo-electric field, NERC has proposed the following formula:

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

Figure 7 – NERC Peak Geo-Electric Field Formula

As discussed in the last section of these comments the α (Alpha) factor in the above formula is understated at all latitudes for the NERC 100 year storm thresholds. In addition, the White Paper illustrates that the NERC proposed β (Beta) factor will also understate the geo-electric field by as much as a factor of 5 times the actual geo-electric field. When these two factors are included and multiplied together in the same formula, this acts to compound the individual understatements of the α and β factors into a significantly larger understatement of Peak Geo-electric field.

This compounding of errors in the α and β factors can be best illustrated from a case study provided in the Kappenman/Radasky White Paper. In this paper, Figure 27 (page 26) provides the geo-electric field recorded at Tillamook Oregon during the Oct 30, 2003 storm. Also shown is the NERC Model calculation for the same storm at this location. As this comparison illustrates, the NERC model understates the actual geo-electric field by a factor of ~5 and that the actual peak geo-electric field during this storm is nearly 1.2 V/km. Further this geo-electric field is being driven by dB/dt intensity at Victoria (about 250km north from Tillamook) that is 150 nT/min. Tillamook is also at ~50 geomagnetic latitude, so it is possible that the 100 year storm intensity could reach 5000 nT/min or certainly much higher than 150 nT/min. When using the NERC formula to calculate the peak Geo-electric field at Tillamook, the following factors would be utilized as specified in the NERC draft standard: For Tillamook Location, the α Alpha Factor = 0.3 based on Tillamook being at ~50 degrees MagLat, the β Beta Factor = 0.62 for PB1 Ground Model at Tillamook. Then using the NERC formula the derived Epeak would be:

"Tillamook Epeak" = 8 x 0.3 x 0.62 = 1.488 V/km (from NERC Epeak Formula)

In comparison to the ~1.2 V/km observed during the Oct 2003 storm, this NERC-derived Peak is nearly at the same intensity as caused by a ~150 nT/min disturbance. The scientifically sound method of deriving the Peak intensity is to utilize Faraday's Law of Induction to estimate the peak at higher dB/dt intensities. Faraday's Law of Induction is Linear (assuming the same spectral content for the disturbance field), which requires that as dB/dt increases, the resulting Geo-Electric Field also increases linearly. Therefore using the assumption of a uniform spectral content, which may be understating the threat environment, extrapolating to a 5000 nT/min peak environment would project a Peak Geo-Electric Field of ~40 V/km, a Factor of ~30 times higher than derived from the NERC Epeak Formula[8].

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[7] John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.

[8] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/150) = 33.3, Peak Electric = 1.2 V/km *33.3 = 40 V/km

A similar derivation can be performed for the GIC and geo-electric field observations at Chester Maine in the White Paper. From Figure 14 (page 17) the dB/dt in the Chester region reached a peak of ~600 nT/min and resulted in a ~2V/km peak geo-electric field during the May 4, 1998 storm. For this case study, the proposed NERC standard and the formula for the Peak Geo-Electric Field using the following factors for the Chester location, the Alpha Factor = 0.6 based on Chester being at ~55^{o} MagLat, the Beta Factor = 0.81 for NE1 Ground Model at Chester. The NERC Formula would derive the Peak being only ~3.88 V/km.

"Chester Epeak" = 8 x 0.6 x 0.81 = 3.88 V/km (from NERC Epeak Formula)

In contrast to the NERC Epeak value, a physics-based calculation can be made for the case study of the May 4, 1998 storm at Chester. Again, Faraday's Law of Induction can be utilized to extrapolate from the observed 600 nT/min levels to a 5000 nT/min threshold. This results in a Peak Geo-Electric Field of ~16.6 V/km, a Factor of ~4.3 higher than derived from the NERC Formula[9].

Discussion of Data-Based GMD Standard to Replace NERC Draft Standard

As prior sections of this discussion has revealed, the proposed NERC Draft Standard does not accurately describe the threat environment consistent with a 1-in-100 Year Storm threshold, rather the NERC Draft Standard proposes storm thresholds that are only a 1-in-10 to 1-in-30 Year frequency of occurrence. Further, the methods proposed by NERC to estimate geo-electric field levels across the US are not validated and where independent assessment has been performed the NERC Geo-Electric Field levels are 2 to 5 times smaller than observed based on direct GIC measurements of the power grid.

Basic input assumptions on ground conductivity used in the NERC ground modeling approach have never been verified or validated. Ground models are enormously difficult to characterize, in that for the frequencies of geomagnetic field disturbances, it is necessary to estimate these profiles to depths of 400kM or deeper. Direct measurements at these depths are not possible to carry out and the conductivity of various rock strata can vary by as much as 200,000%, creating enormous input modeling uncertainties for these ground profiles. Further it has been shown that the NERC geo-electric field modeling calculations themselves appear to have inherent frequency cutoff's that produce underestimates of geo-electric fields as the disturbance increases in intensity and therefore importance. Hence the NERC Standard is built entirely upon flawed assumptions and has no validations.

A framework for a better Standard which is highly validated and accurate has been provided via the Kappenman/Radasky White Paper and the discussion provided in these comments. As noted in the White Paper, the availability of GIC data and corresponding geomagnetic field disturbance data allowed highly refined estimates to be performed for geo-electric fields and to extrapolate the Geo-Electric Field to the 100 Year storm thresholds for these regions. The primary inputs (other than GIC and corresponding geomagnetic field observations) are simply just details on the power grid circuit parameters and circuit topology. These parameters are also known to very high precision (for example transmission line resistance is known to 4 significant digits after the decimal point). Asset locations are

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[9] Extrapolating to higher dB/dt using Faraday's Law of Induction requires only multiplication by the ratio of Peak dB/dt divided by observed dB/dt to calculate Peak Electric Field, in this case Ratio = (5000/600) = 8.3, Peak Electric = 2 V/km *8.3 = 16.6 V/km

also known with high precision and many commercially available simulation tools can readily compute the GIC for a uniform 1 V/km geo-electric field. This calculation provides an intrinsic GIC flow benchmark that can be used to convert any observed GIC to an regionally valid Geo-Electric Field that produced that GIC. Further this calculation is derived over meso-scale distances on the actual power grid assets of concern. As summarized in a recent IEEE Panel discussion, this approach allows for wide area estimates of ground response than possible from conventional magneto-telluric measurements[10]. Figure 8 provides a map showing the locations of the Chester, Seabrook and Tillamook GIC observations and the approximate boundaries based upon circuit parameters of the ground region that were validated.

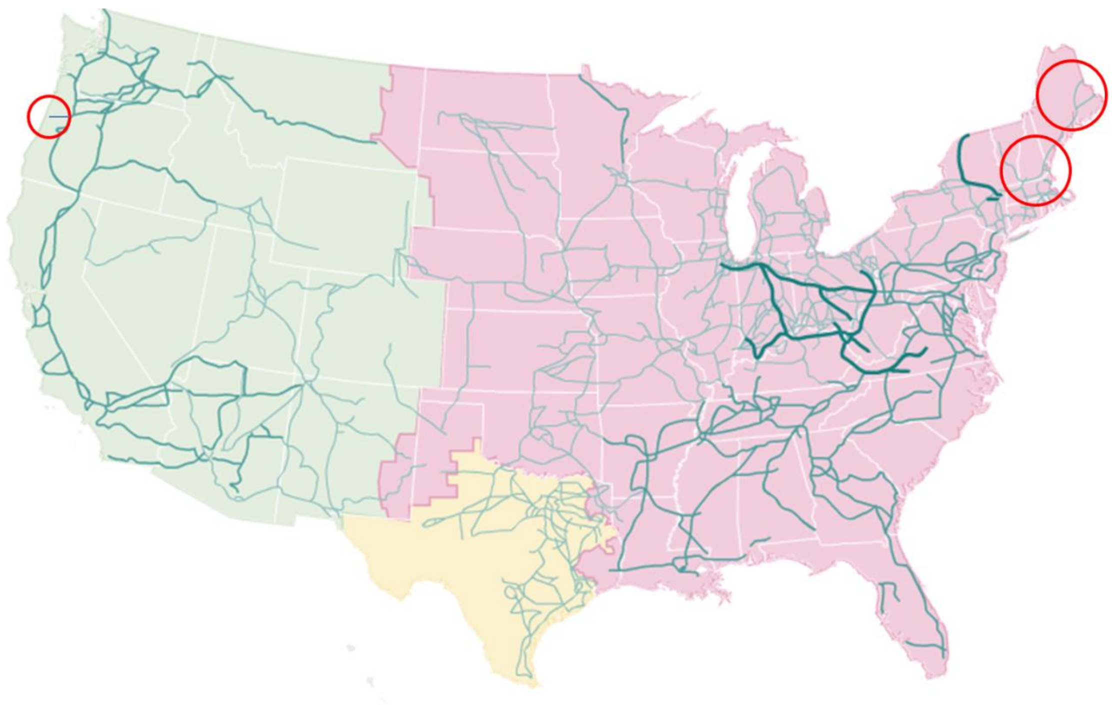

Figure 8 – Red Circles provide Region of Ground Model Validation using GIC observations from Kappenman/Radasky White Paper.

As filed in a recent FERC Docket filing[11], ~100 GIC monitoring sites have operated and are collecting data across the US. Using these analysis techniques and the full complement of GIC monitoring locations, it is possible to accurately benchmark major portions of the US as shown in the map in Figure 9. As shown in this figure, the bulk of the Eastern grid is covered and in many locations with overlapping benchmark regions, such that multiple independent observations can be used to confirm the accuracy of the regional validations. The same is also true for much of the Pacific NW. As noted in Meta-R-319 and shown below is Figure 10 from that report, these two regions are the most at-risk regions of the US Grid.

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[10] Kappenman, J.G., "An Overview of Geomagnetic Storm Impacts and the Role of Monitoring and Situational Awareness", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[11] Foundation for Resilient Societies, "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND", Docket No. RM14-1-000, submitted to FERC on August 18, 2014.

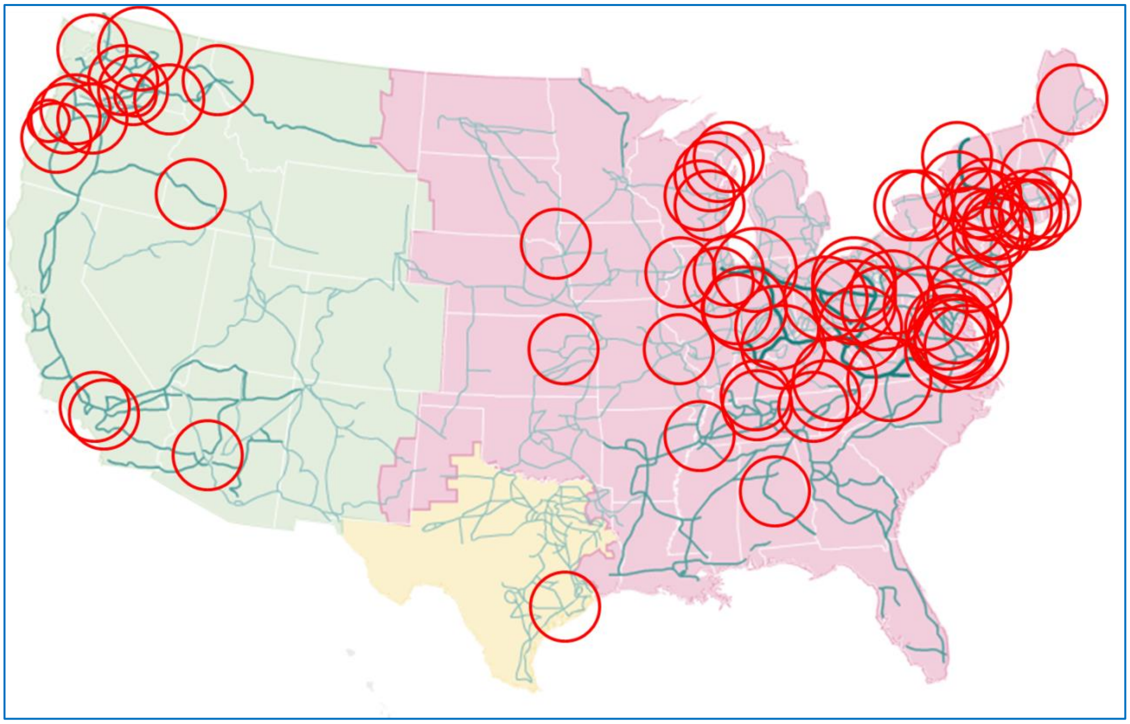


Figure 9 – GIC Observatories and US Grid-wide validation regions.

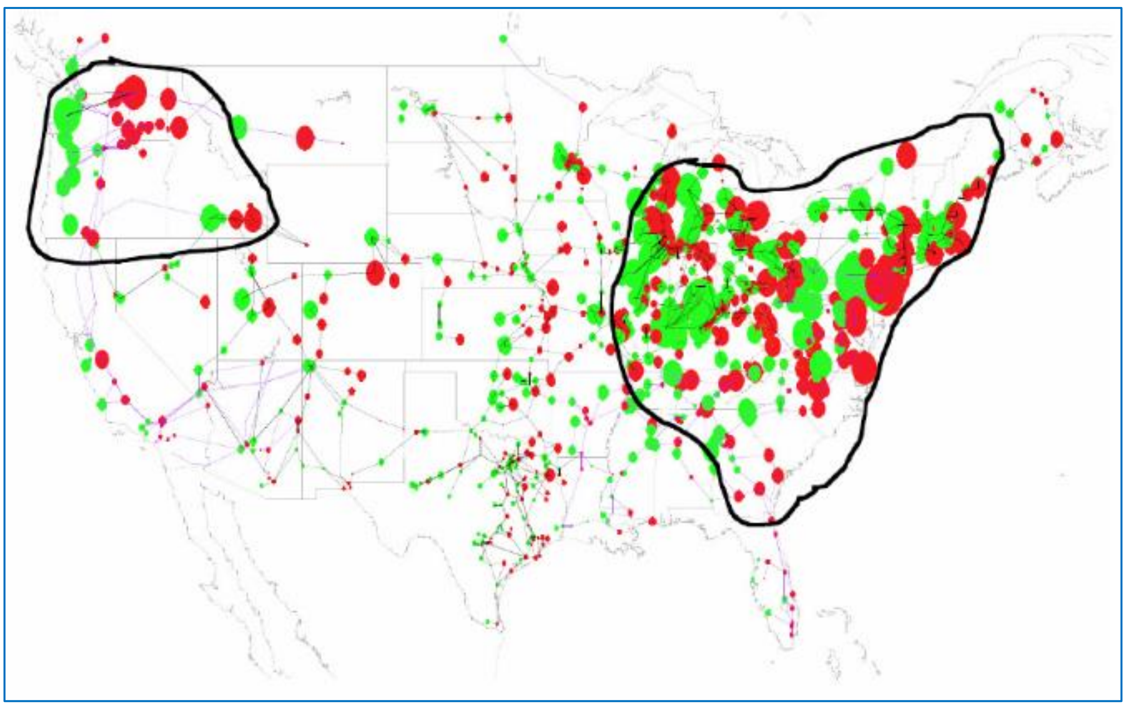


Figure 10 – Map of At-Risk Regions from Meta-R-319 Report for 50^{o} Severe Storm Scenario

Each of these GIC measurements can define and validate the geo-electric field parameters over considerable distance. In the example of the Chester Maine case study, the validations in the case of the 345kV system can extend ~ 250kM radius. At higher kV ratings, the footprint of GIC and associated geo-electric field measurements integrates over an even larger area. As these measurements are accumulated over the US, the characterizations provide a very complete coverage with many

overlapping coverage confirmations. These confirmations will also have Ohm's law degree of accuracy, whereas magnetotelluric observations can still have greater than factor of 2 uncertainty[12]. For those areas where perhaps a GIC observation is not available, this region can utilize a base intensity level that agrees with neighboring systems until measurements can be made available to fully validate the regional characteristics.

This Observational-Based Standard further establishes a more accurate framework for developing the standard using facts-based GIC observation data as well as the laws of physics[13], and removes the dependence on simulation models which could be in error. The power system and GIC flows observed on this system will always obey the laws of physics while models may exhibit erratic behaviors and are dependent on the skill/qualifications of the modeler and the uncertainty of model inputs. Models are always inferior to actual data as they cannot incorporate all of the factors involved and can have biases which can inadvertently introduce errors. This Observational Framework methodology is also open and transparent so any and all interested parties can review and audit findings. The validations can be performed quickly and inexpensively across all of these observational regions. It also allows for simple updates once new transmission changes are made over time as well.

Respectfully Submitted by,

John Kappenman, Principal Consultant
Storm Analysis Consultants

Curtis Birnbach, President and CTO
Advanced Fusion Systems

[12] Boteler, D., "The Influence of Earth Conductivity Structure on the Electric Fields that drive GIC in Power Systems", IEEE Panel Session on GIC Monitoring and Situational Awareness, IEEE PES Summer Meeting, July 30, 2014.

[13] For example, Ohm's Law and Faraday's Law of Induction

Comments on NERC TPL – 007 – 1 (R5)

Reference s*creening criterion for GIC Transformer Thermal Impact Assessment*

Issue

A level of 15 Amps / phase was selected for this screening. It was based on temperature rise measurements of structural parts of some core form transformers reaching a level of 50 K upon application of 15 Amps / phase DC.

Comment – 1

Since the time constant of the transformer structural parts is typically in the 10 – minute range, these temperatures were reached after application of the DC current for 10's of minutes (up to 50 minutes in some cases). The high level GIC pulses are typically of much shorter duration and the corresponding temperature rise would be a fraction of these temperature rises.

Recommendation

Upon performing temperature calculations of the cases referenced in the NERC screening White paper for GIC pulses, we suggest the following:

1. The 15 Amps / phase could be kept as a screening criterion for GIC levels extending over; say, 30 minutes.
2. A higher level of 50 Amps / phase is used as a screening criterion for high – peak, short – duration pulses. A 3 – minute duration of 50 Amps would be equivalent to, and even more conservative than, the 15 Amps / phase steady state.

Comment – 2

The 15 Amps / phase level was based on measurements on transformers with core – types, other than 3 – phase, 3 – limb cores. Three Phase core form transformers with 3 – limb cores are less susceptible to core saturation.

Recommendation

We suggest that, for 3 – phase core form transformers with 3 – limb cores, a higher level of GIC, for example 30 or 50 Amps / phase, is selected for the screening level for the base GIC and correspondingly

a much higher level, for example, 100 Amps / phase, for the high – peak, short – duration GIC pulses.

Note 1:

The revised screening criterion recommended in the above, is not only more appropriate technically than what is presently suggested in the NERC "Thermal screening" document, but also will reduce the number of transformers to be thermally assessed probably by a factor of 10; which would make the thermal evaluation of the ≥ 200 kV transformer fleet in North America to be more feasible to be done in the time period required by the NERC document.

Note 2:

It is to be noted that proposing one value of GIC current for screening for all transformer types (core form vs. shell form), sizes, designs, construction, etc. is not technically correct. However, for the sake of moving the NERC document forward, we agreed to follow the same path but provide the improved criterion we recommended above.

Submitted by:

Mr. Raj Ahuja, Waukesha
Mr. Mohamed Diaby, Efacec
Dr. Ramsis Girgis, ABB
Mr. Sanjay Patel, Smit
Mr. Johannes Raith, Siemens

Comments on NERC TPL – 007 – 1 (R6)

"GIC Transformer Thermal Impact Assessment"

Issue

The document should have a Standard GIC signature to be used for the thermal impact Assessment of the power Transformer fleet covered by the NERC document.

Comment – 1

Users would not be able to predict, to any degree of accuracy, what GIC signature a transformer would be subjected to during future GMD storms. This is since the actual GIC signature will depend on the specific parameters and location of the future GMD storms. Unless a user requires thermal assessment of their fleet of transformers to actual GIC signatures, the user should be able to use a Standard GIC Signature; where the parameters of the signature (magnitudes and durations of the different parts of the signature) would be specified by the user.

This is parallel to the standard signatures used by the transformer / utility industry Standards (IEEE & IEC) for lightning surges, switching surges, etc.; where standard signatures (wave – shapes) are used for evaluating the dielectric capability of transformers.

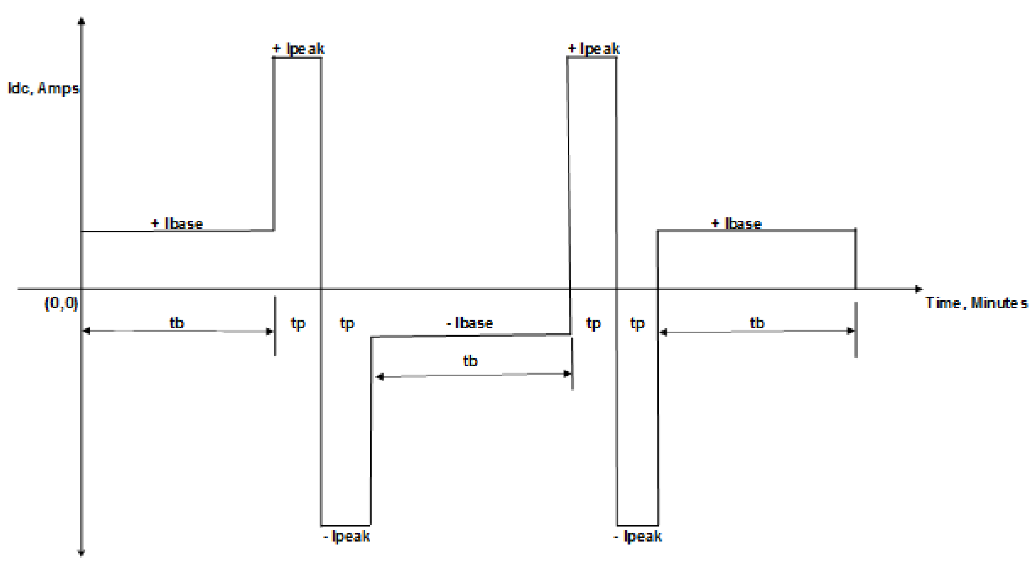
Recommendation

We recommend that the NERC document suggest using the Standard GIC signature, proposed in the upcoming IEEE Std. PC57.163 GIC Guide, shown below. This signature was based on observation / study of a number of signatures of measured GIC currents on a number of power transformers located in different areas of the country. It was recognized that GIC current signatures can be generally characterized by a large number of consecutive narrow pulses of low – to – medium levels over a period of hours interrupted by high peaks of less than a minute, to several minutes, duration. Therefore, GIC signatures are made of two main stages of GIC; namely:

- Base Stage: Consists of multiples of small – to – moderate magnitudes of GIC current sustained for periods that could be as short as a fraction of an hour to several hours.
- Peak GIC Pulse Stage: Consists of high levels of GIC pulses of durations of a fraction of a minute to several minutes.

Utilities would provide values of the Base GIC (I_{base}) current and the Peak GIC current pulses (I_{peak}) specific to their power transformers on their respective power system. These two parameters are to be determined based on the geographic location of the transformer as well as the part of the power grid the transformer belongs to. For standardization purposes, the time durations of the base GIC and GIC pulses; t_b and t_p, respectively, can be fixed at 20 minutes and 3 minutes; respectively. Also, the full duration of the high level GMD event can be standardized to be 2 or 3 hours long; encompassing several cycles of the GIC signature. These parameters can be as conservative as they need to be.

Specifying a Standard GIC signature for the thermal Assessment of the thousands of power Transformers covered by the NERC document would allow using generic / simplified (but sufficiently accurate) thermal models for the thermal Assessment and, hence, a significantly less effort. On the other hand, the thermal Assessment of transformers, to be done correctly, for different more complex GIC signatures, would require much more time to complete.



Submitted by:

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EIS Council Comments on Benchmark GMD Event

TPL-007-1

Submitted on October 10, 2014

Introduction

The Electric Infrastructure Security Council's mission is to work in partnership with government and corporate stakeholders to host national and international education, planning and communication initiatives to help improve infrastructure protection against electromagnetic threats (e-threats) and other hazards. E-threats include naturally occurring geomagnetic disturbances (GMD), high-altitude electromagnetic pulses (HEMP) from nuclear weapons, and non-nuclear EMP from intentional electromagnetic interference (IEMI) devices.

In working to achieve these goals, EIS Council is open to all approaches, but feels that industry-driven standards, as represented by the NERC process, are generally preferable to government regulation. That said, government regulation has proven necessary in instances (of all kinds) when a given private sector industry does not self-regulate to levels of safety or security acceptable to the public. EIS Council is concerned that the new proposed GMD benchmark event represents an estimate that is too optimistic, and would invite further regulatory scrutiny of the electric power industry.

The proposed benchmark GMD event represents a departure from previous GMDTF discussions, where the development of the "100-year" benchmark GMD event appeared to be coming to a consensus, based upon statistical projections of recorded smaller GMD events to 100-year storm levels. These levels of 10 – 50 V/km, with the average found to be 20 V/km, were also in agreement with what were thought to be the storm intensity levels of the 1921 Railroad Storm, which, along with the 1859 Carrington Event, were typically thought to be the scale of events for which the NERC GMDTF was formed to consider.

The new approach described in April 14, 2014 Draft (and subsequent GMDTF meetings and discussions) contains several key features that EIS Council does not consider to yet have enough scientific rigor to be supported, and would therefore recommend that a more conservative or "pessimistic" approach should be used to ensure proper engineering safety margins for electric grid resilience under GMD conditions. These are:

1. The introduction of a new "spatial averaging" technique, which has the effect of lowing the benchmark field strengths of concern from 20 V/km to 8 V/km;

2. A lack of validation of this new model, demonstrating that it is in line with prior observed geoelectric field values;

3. The use of the 1989 Quebec GMD event as the benchmark reference storm, rather than a larger known storm such as the 1921 Railroad storm;

4. The use of 60 degrees geomagnetic latitude as the storm center; and

5. The use of geomagnetic latitude scaling factors to calculate expected storm intensities south of 60 degrees.

Spatial Averaging and Model Validation

The introduction of the spatial averaging technique is a novel introduction to discussions of the GMDTF. While the concept could prove to have validity, the abrupt change to a new methodology at this time is not fully understood by the GMDTF membership, nor has it yet had any peer review by the larger space weather scientific community. In order to ensure confidence that this is a proper approach, it is necessary that this approach be validated with available data via the standard peer-review process.

Prior findings of the GMDTF of a 20 V/km peak field values were shown to be in line with prior benchmark storms such as the 1921 Railroad storm, for which there is very good magnetometer data across the United States and Canada. Even for the 1989 Quebec Storm, on which this new benchmark is supposed to be based, it is not clear whether the new spatial averaging technique has been demonstrated to be in line with the known magnetometer data. This would seem to be a fairly straightforward validation of this new model, but is currently lacking in the description of the new approach.

The spatial averaging method also appears to be at odds with standard engineering safety margin design approaches. As an example, if the maximum load for a bridge is 20 tons, but the average load is 8 tons, a bridge is designed to hold at least 20 tons, or more typically 40 tons, a factor of two safety margin over the reasonably expected maximum load. It is recommended that the screening criteria be increased to encompass the maximum credible storm event, rather than an average, in line with typically accepted best practices for engineering design.

The description of the method does describe that within the expected spatially-averaged GMD event of 8 V/km, that smaller, moving "hot spots" of 20 V/km are expected. It therefore seems prudent for electric power companies to analyze the expected resilience of their system against a 20 V/km geoelectric field, as any given company could find themselves within such a "hot spot" during a GMD event.

One further point to consider is that, while the GMDTF scope does not at present include EMP, the unclassified IEC standard for the geoelectric fields associated with EMP E3 is 40 V/km. Should the scope of the GMDTF or FERC order 779 ever be expanded to include EMP E3, 40 V/km is the accepted international standard, something to consider when setting the benchmark event, as any given power company could find themselves subject to the maximum credible EMP E3 field.

1989 Quebec Storm as the Benchmark Event

The 1989 Quebec Storm is very well-studied event, and is a dramatic example of the impacts of GMD on power grids. The loss of power in the Province of Quebec, failure of the Salem transformer, and other grid anomalies associated with the storm are all well documented. The GMDTF was formed, and FERC Order 779 issued, to ensure grid resilience for events that will be much larger than the 1989 Quebec Storm, such as the 1921 Railroad Storm. The two figures below show a side-by-side comparison of the 1989 and 1921 storms. The geographic size, and also the latitude locations are quite striking.

The use of the 1989 Quebec Storm as the benchmark event is of concern because simply scaling the field strengths of the 1989 Storm higher (an “intensification factor” of 2.5 is used), but leaving the same geographic footprint, does not appear to be a valid approach. While the 2.5 scaling factor is described to produce local “hot spots” of 20 V/km, in agreement with earlier findings, it fails to consider the well-known GMD phenomena that the electrojets of larger storms shift southward, as can be seen in comparing the two figures. By using the geographic footprint of the 1989 storm, the new benchmark will predict geoelectric field levels that are incorrect for geomagnetic latitudes below 60 degrees, where the center of the new benchmark storm has been set.

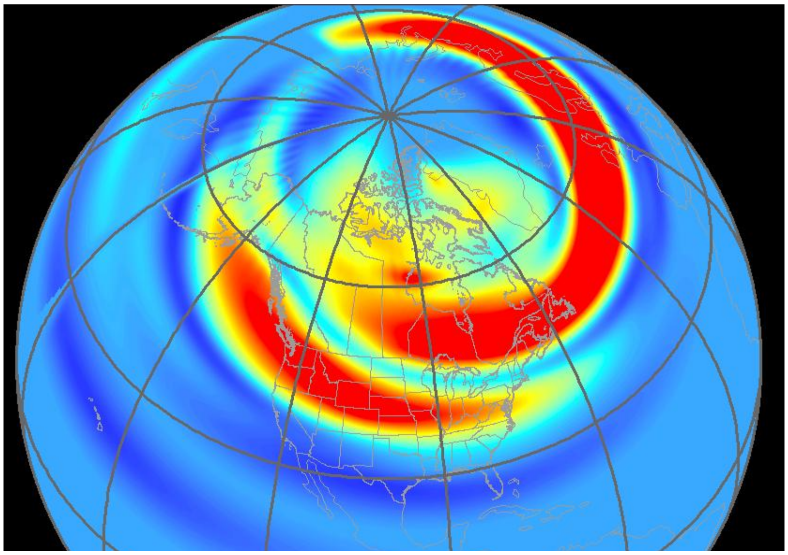

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

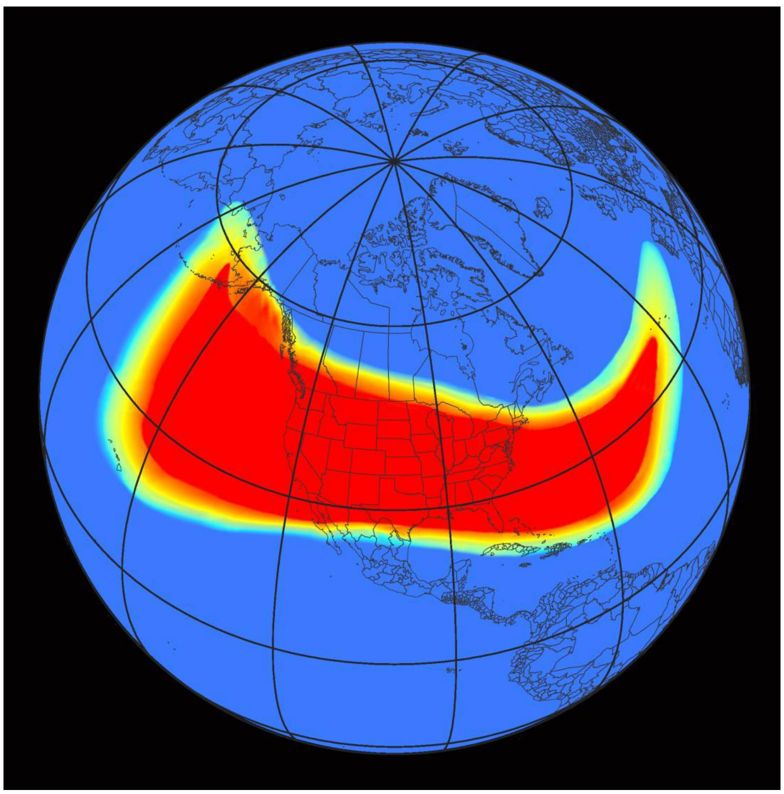

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

As the figures above show, GMD events larger than the 1989 Quebec event are expected to be larger in overall geographic laydown (continental to global in scale), and also to be centered at lower geomagnetic latitudes than the 1989 storm, due to a southward shifting of the auroral electrojet for more energetic storms. While the latitudinal scaling factor α may be correct for a storm like the 1989 Storm and centered on 60 degrees geomagnetic latitude, use of these scaling factors does not appear to be valid for GMD events where the storm will be centered at a lower latitude, and have a larger geographic footprint. While the β factor - which captures differences in geologic ground conductivity - will remain valid under all storm scenarios, the α factors would only be valid for a storm centered at 60 degrees. For example, in looking at figure 2 above, the storm is quite large, and centered at (roughly) 40 – 45 degrees North Latitude. The correct α factor for 45 degrees in this case would be 1, rather than the 0.2 value that would be correct for a storm centered at 60 degrees North Latitude. As it is not known what the center latitude of any given storm center would be, it would seem that the use of the 60 degree storm center latitude and subsequent α scaling factors is not fully supported.

Supporting scientific evidence for the use of the 60-degree storm center and scaling factors is cited in TPL-007-1. The supporting paper by Ngwira et al[1], however, discusses a "latitude threshold boundary [that] is associated with the movements of the auroral oval and the corresponding auroral electrojet current system." The latitude boundary found in the paper, however, is given as 50 degrees magnetic latitude, rather than 60 degrees. The study determines this boundary based on observations of ~30 years of geomagnetic storm data. While the data set is large, it does not contain very large storms, on the scale of the 1921 Railroad storm. As the largest storms are known to have the largest southward electrojets shifts, it would seem prudent that the benchmark be adjusted to be consistent with the supporting scientific finding of 50 degrees magnetic latitude, and a subsequent re-calculation of the α scaling factors for latitudes below 50 degrees.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed

[1] Ngwira, Pulkkinen, Wilder, and Crowley, *Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications*, Space Weather, Vol. 11 121-131 (2013)

discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there would seem to be a scientific inconsistency in using a benchmark storm centered at 60 degrees geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location down to 50 degrees, as cited in the supporting document. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, centered at the cited 50 degree magnetic latitude threshold boundary, with subsequently updated latitude scaling factors for lower latitudes, as the benchmark event against which the individual electric power companies can analyze their system resilience.

Response to NERC Request for Comments on TPL-007-1

Comments Submitted by the Foundation for Resilient Societies
October 10, 2014

The Benchmark Geomagnetic Disturbance (GMD) Event whitepaper authored by the NERC Standard Drafting Team proposes a conjecture that geoelectric field "hotspots" take place within areas of 100-200 kilometers across but that these hotspots would not have widespread impact on the interconnected transmission system. Accordingly, the Standard Drafting Team averaged geoelectric field intensities downward to obtain a "spatially averaged geoelectric field amplitude" of 5.77 V/km for a 1-in-100 year solar storm. This spatial averaged amplitude was then used for the basis of the "Benchmark GMD Event."[1]

In this comment, we present data to show the NERC "hotspot" conjecture is inconsistent with real-world observations and the "Benchmark GMD Event" is therefore not scientifically well-founded.[2] Figures 1 and 2 show simultaneous GIC peaks observed at three transformers up to 580 kilometers apart, an exceedingly improbable event if NERC's "hotspot" conjecture were correct.

According to Faraday's Law of induction, geomagnetically induced current (GIC) is driven by changes in magnetic field intensity (dB/dt) in the upper atmosphere. If dB/dt peaks are observed simultaneously many kilometers apart, then it would follow that GIC peaks in transformers would also occur simultaneously many kilometers apart. Figure 3 shows simultaneous dB/dt peaks 1,760 kilometers apart during the May 4, 1988 solar storm.

In summary, the weight of real-world evidence shows the NERC "hotspot" conjecture to be erroneous. Simultaneous GIC impacts on the interconnected transmission system can and do occur over wide areas. The NERC Benchmark GMD Event is scientifically unfounded and should be revised by the Standard Drafting Team.

[1] See Appendix 1 for excerpts from the "Benchmark Geomagnetic Disturbance Event Description" whitepaper relating to NERC's "spatial averaging" conjecture.
[2] Data compilations in Figures 1 and 2 are derived from the AEP presentation given to the NERC GMD Task Force in February 2013. Figure 3 is derived from comments submitted to NERC in the Kappenman-Radasky Whitepaper.

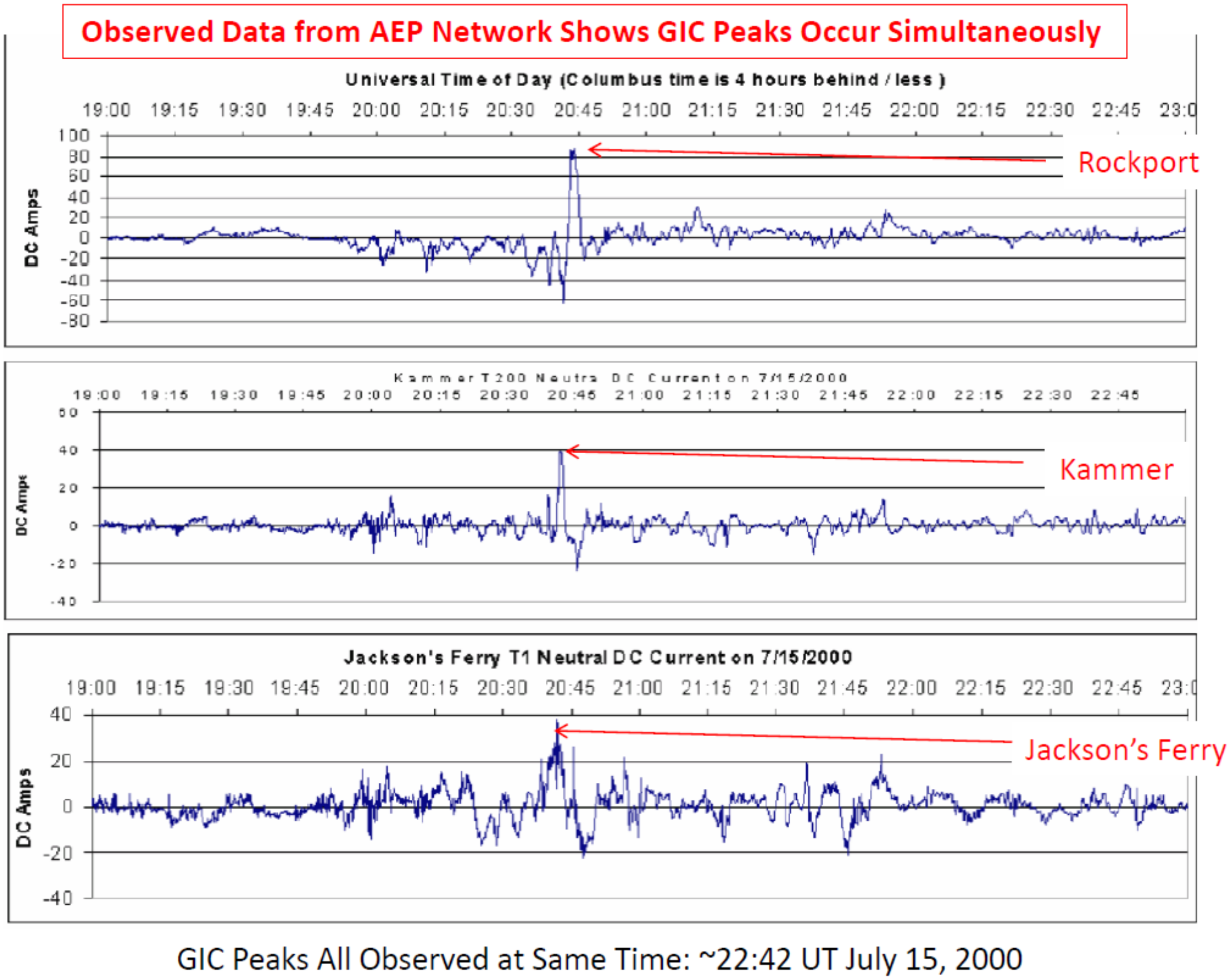

Figure 1. American Electric Power (AEP) Geomagnetically Induced Current Data Presented at February 2013 GMD Task Force Meeting

Locations and Distances for GIC Peaks at Kammer, Jackson's Ferry, and Rockport Transformers

All Peaks Observed Simultaneously at ~22:42 Universal Time on July 15, 2000

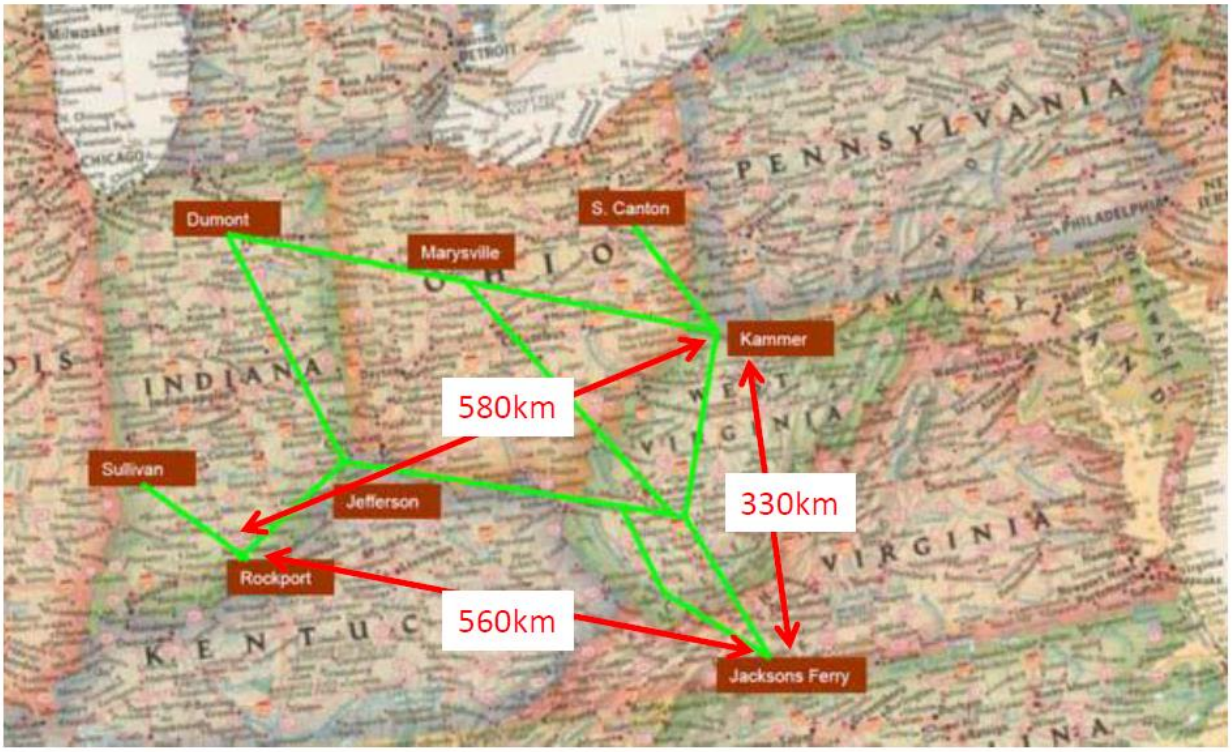

Figure 2. Location of Transformer Substations with GIC Readings on Map of States within AEP Network

Magnetometer Readings from Ottawa and St. John's Observatories During May 4, 1988 Solar Storm Show Simultaneous dB/dt Peaks Far Apart

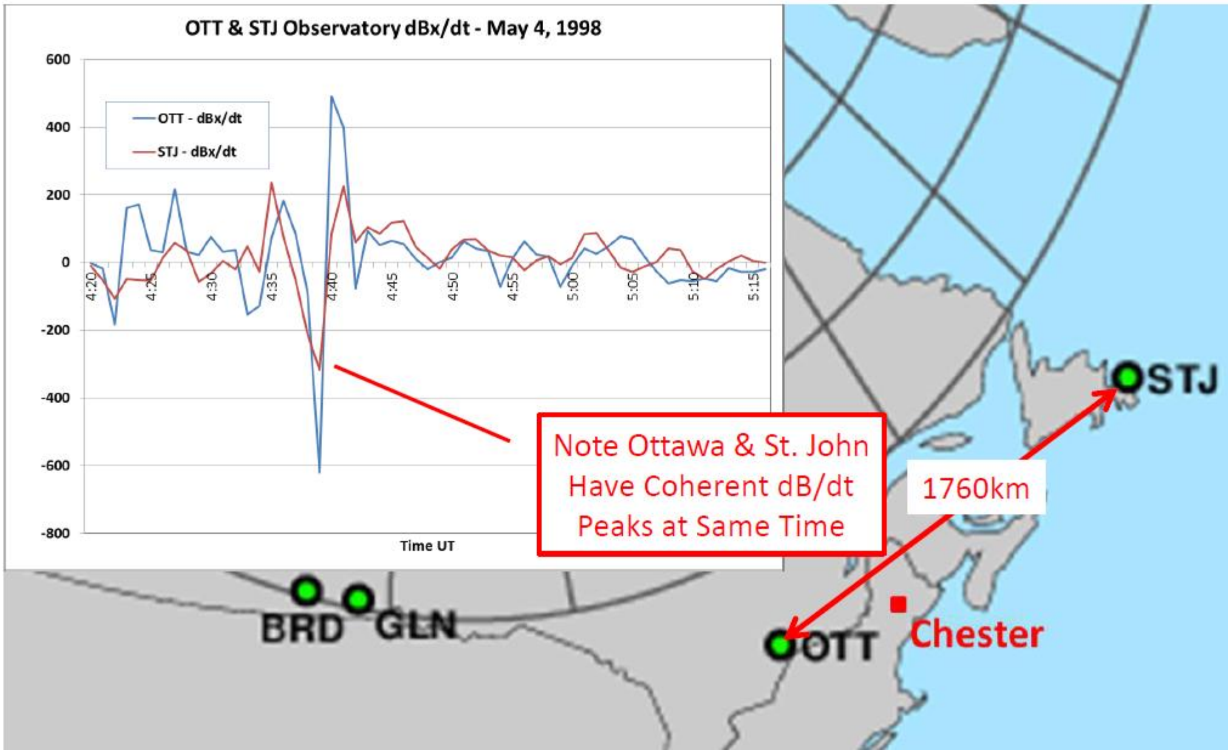

Figure 3. Magnetometer Readings Over Time from Ottawa and St. John Observatories

Appendix 1

Excerpts from
Benchmark Geomagnetic Disturbance Event Description

North American Electric Reliability Corporation

Project 2013-03 GMD Mitigation

Standard Drafting Team

Draft: August 21, 2014

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

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[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

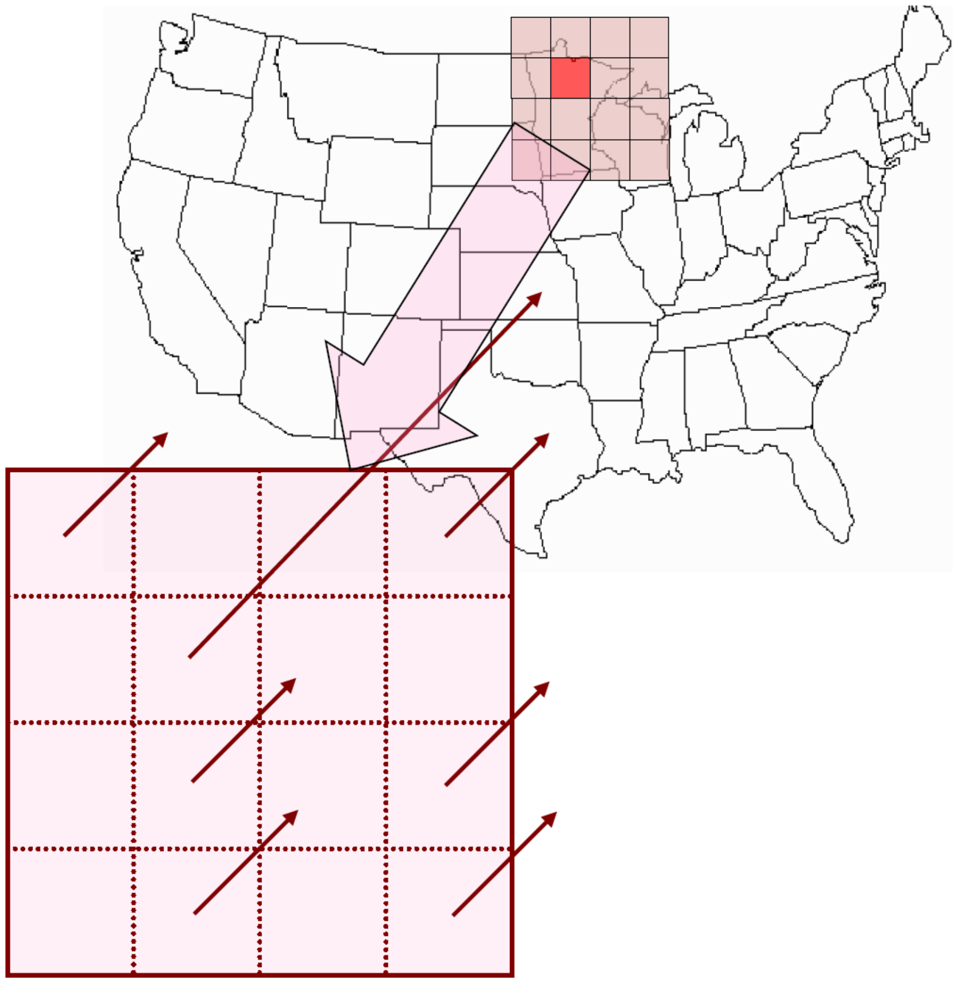

Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address <u>wide-area</u> effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

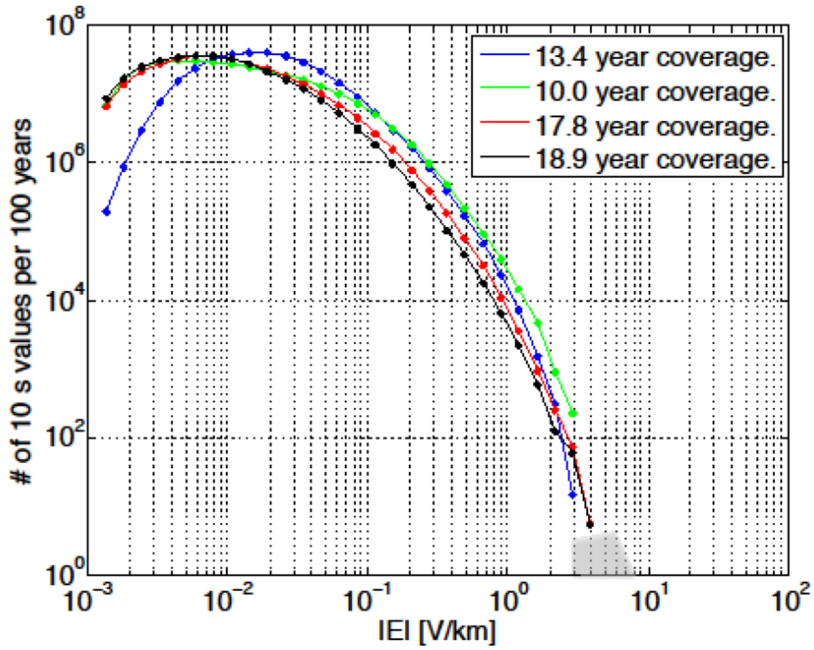

Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

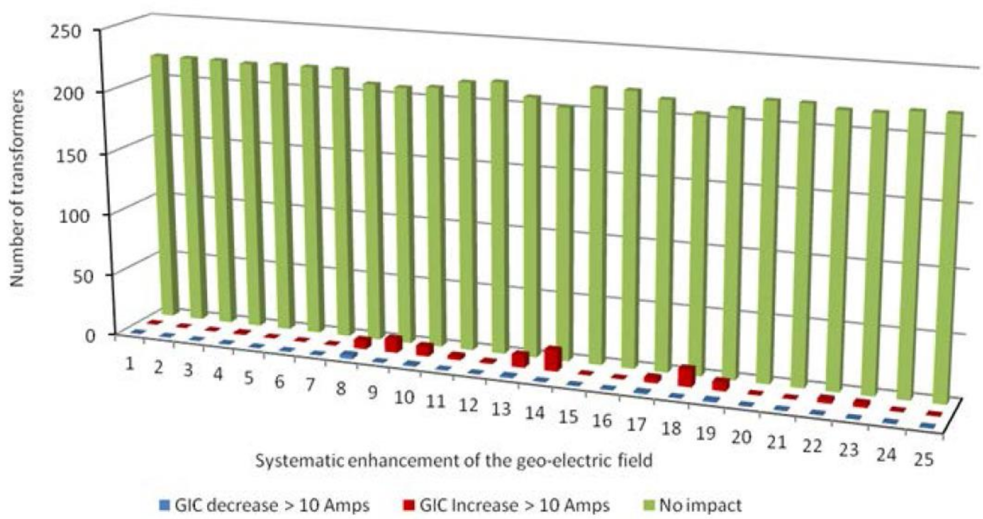

Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

---

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

Mark Olson

From:	Gale Nordling <gnordling@emprimus.com>
Sent:	Thursday, November 20, 2014 3:36 PM
To:	Mark Olson; Mark Lauby; Thomas Burgess; Mark Rossi; John Moura
Subject:	NERC Geomagnetic and Geoelectric Field Benchmark Model and Recommendations
Attachments:	Chinese paper on GIC Curents Liu et al 2014.pdf; GMD Correlated Equipment Insurance Claims.pdf; PESGM2013-000013_Generators.pdf; NERC Formula Compared to China Data rev 1.xlsx

New studies and papers bring significant clarity and information relevant to the proposed NERC GMD standards. Please accept the following comments for additional changes to NERC GMD Benchmark Model as recently revised:

1. We renew all previous comments and objections.

2. Changing transformer thermal screening criteria to 75 amps/phase from 15 amps/phase would not meet industry best practices for grid operation because:
   a. Some transformers have a GIC rating under 75 amps/phase
   b. The standard would suggest there is little or no damage to electrical equipment until you reach 75 amps/phase of GIC. The Luis Marti paper attached suggests rotor damage due to harmonics when GIC reaches levels of 50 or more amps/phase.

3. The NERC Benchmark formula modified further for latitude and soil does not give results that are anywhere near actual data. In fact a calculation that we have made (see attached Excel spreadsheet) for actual data recorded in China (see attached Chinese paper) would suggest the NERC Benchmark formula understates the actual geoelectric field by a <u>factor</u> of 22 (not 22%). For the Benchmark Model to be used to determine grid reliability and mitigation for public health and safety (and national security), the Benchmark Model must be consistent with actual data.

4. The Benchmark Model does very little to address harmonics and damage to both customer equipment and to utility equipment. Attached is a recent study done by Lockheed Martin, Zurich and NOAA in which claims for damage to customers were correlated to GMD events during the period of 2000-2010. The study shows in excess of $2 Billion of damage per year in the US due to low level solar storms (due to harmonics). The solar storms for this period are nowhere near in size to either the Carrington event or even the 1989 Quebec solar event. This would suggest that utilities on a regular year to year basis are in violation of IEEE 519 for both FERC approved wholesale contracts and for power delivered to customers. Customers on the distribution side are being damaged every year by harmonics. The NERC proposed standards don't address this virtually at all, and don't deal with either the ordinary year to year solar storms or the severe solar superstorms on the damage to customers and the violations of IEEE 519. This new study also found little or no difference in damage due to latitude which would suggest the NERC standard is wrong on latitude adjustments as well. Latitude adjustments must also be justified by actual data. This new study also changes the issue of harmonics from a low frequency (ie one in 50 or 100 year event) to an every year event which must be addressed for all levels of solar storm.

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Research Article

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Observations and modeling of GIC in the Chinese large-scale high-voltage power networks

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ABSTRACT

During geomagnetic storms, the geomagnetically induced currents (GIC) cause bias fluxes in transformers, resulting in half-cycle saturation. Severely distorted exciting currents, which contain significant amounts of harmonics, threaten the safe operation of equipment and even the whole power system. In this paper, we compare GIC data measured in transformer neutrals and magnetic recordings in China, and show that the GIC amplitudes can be quite large even in mid-low latitude areas. The GIC in the Chinese Northwest 750 kV Power Grid are modeled based on the plane wave assumption. The results show that GIC flowing in some transformers exceed 30 A/phase during strong geomagnetic storms. GIC are thus not only a high-latitude problem but networks in middle and low latitudes can be impacted as well, which needs careful attention.

Key words. electric circuit – geomagnetically induced currents (GIC) – modelling – engineering – space weather

1. Introduction

During strong space weather storms, which are caused by the activity of the Sun, the Earth's magnetic field is intensely disturbed by the space current system in the magnetosphere and ionosphere. The electric fields induced by time variations of the geomagnetic field drive geomagnetically induced currents (GIC) in electric power transmission networks. The frequencies of GIC are in the range of 0.0001 ~ 0.1 Hz. Such quasi-DC currents cause bias fluxes in transformers, which result in half-cycle saturation due to the nonlinear response of the core material (e.g., Kappenman & Albertson 1990; Molinski 2002; Kappenman 2007). The sharply increased magnetizing current with serious waveform distortion may lead to temperature rise and vibration in transformers, reactive power fluctuations, voltage sag, protection relay malfunction, and possibly even a collapse of the whole power system (e.g., Kappenman 1996; Bolduc 2002).

Large GIC are usually considered to occur at high latitudes such as North America and Scandinavia, where tripping problems and even blackouts of power systems due to GIC have been experienced (Bolduc 2002; Pulkkinen et al. 2005; Wik et al. 2009). Large currents in transformer neutrals have been monitored in the Chinese high-voltage power system many times during geomagnetic storms although China is a mid-low-latitude country. At the same time, transformers have had abnormal noise and vibration. Those events have been shown to be caused by GIC based on analyses of simultaneous magnetic data and GIC recordings (Liu & Xie 2005; Liu et al. 2009a). The power grids are using higher voltages, longer transmission distances, and larger capacity with the developing economy in China. So, the risk that the power systems would suffer from GIC problems may obviously increase. The Chinese Northwest 750 kV power grid has long transmission lines with small resistances making it prone to large GIC during geomagnetic storms. Thus it is important to model GIC particularly in that network.

2. GIC observations in Chinese high-voltage power grid

We acquire GIC data through the neutral point of the transformer at the Ling'ao nuclear power plant (22.6° N, 114.6° E) in the Guangdong Province. Besides, geomagnetic field data are collected from the Zhaoqing Geomagnetic Observatory (23.1° N, 112.3° E) which is not very far from Ling'ao. Figure1 shows the neutral point current (top panel), the horizontal component of the geomagnetic field (bottom panel), and its variation rate (middle panel) during the magnetic storms on 7–8 (a) and 9–10 (b) November 2004. The occurrence times of the current peaks match with those of the geomagnetic field variation rate. It is confirmed that there is no HVDC (high-voltage direct current) monopole operation during that time. So it is reasonable to believe that the currents are really GIC induced by geomagnetic storms. The maximum value of GIC is up to 75.5 A/3 phases, which is much higher than the DC bias caused by monopole operation of HVDC.

3. Modeling GIC in power grids

The modeling of GIC in a power grid can be divided into two steps (e.g., Pirjola 2000): step 1, calculating the geoelectric field induced by a magnetic storm; step 2, calculating the GIC in the power grid. The effect of the induced geoelectric field is equivalent to voltage sources in the transmission lines, which enables converting the GIC calculation into a circuit problem in step 2.

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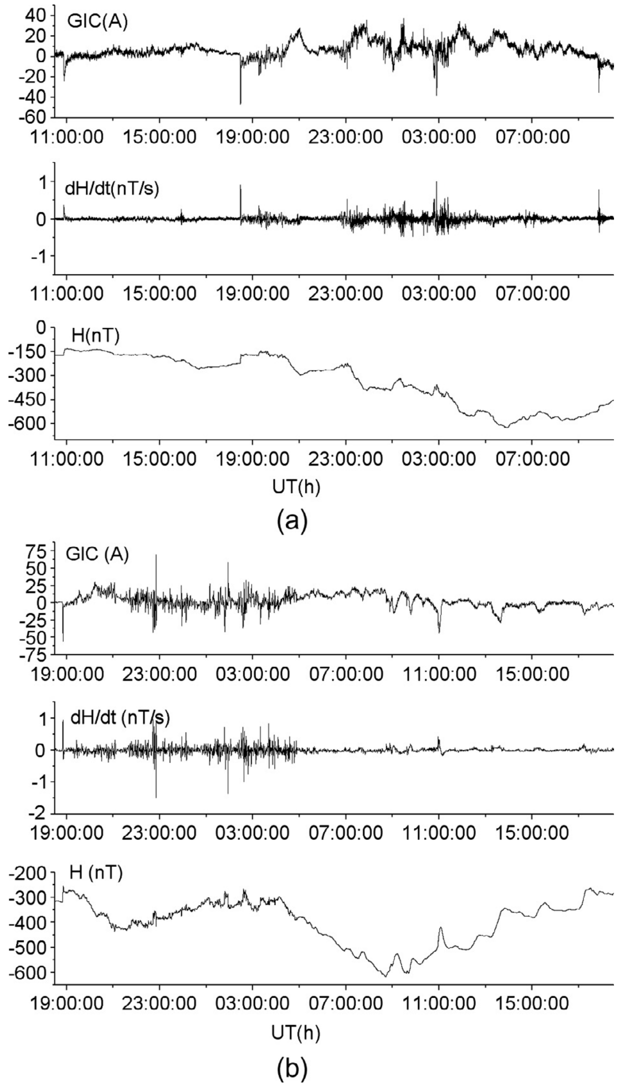

Fig. 1. GIC data at the Ling'ao nuclear power plant on 7–8 (a) and 9–10 (b) November 2004. The horizontal component of the geomagnetic field and its variation rate are also shown based on data from the Zhaoqing Geomagnetic Observatory.

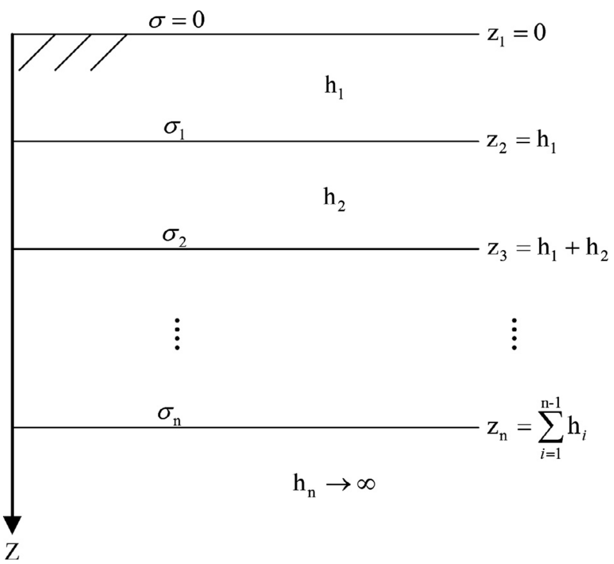

Fig. 2. Layered Earth model for calculating the induced geoelectric field.

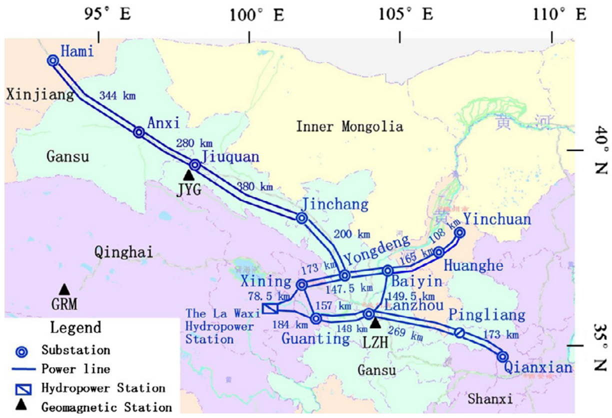

Fig. 3. Chinese Northwest 750 kV power grid. Three geomagnetic observatories (GRM, LZH, and JYG) are also shown on the map. (The WMQ observatory is not located in the area of this map.)

Table 1. Locations of geomagnetic observatories in the area of the Chinese Northwest 750 kV power grid.

Name	Longitude (°E)	Latitude (°N)
WMQ	87.7	43.8
GRM	94.9	36.4
LZH	103.8	36.1
JYG	98.2	39.8

3.1. Calculating the electric field using a layered earth model

We use the standard conventional Cartesian geomagnetic coordinate system in which the x, y and z axes point northwards, eastwards, and downwards, respectively. According to the plane wave assumption (e.g., Boteler 1999), the relation between perpendicular horizontal components of the geoelectric (E) and geomagnetic (B) fields at the earth's surface can be expressed as

$$E_x(\omega) = \frac{1}{\mu_0} B_y(\omega) Z(\omega), \tag{1}$$

$$E_y(\omega) = -\frac{1}{\mu_0} B_x(\omega) Z(\omega), \tag{2}$$

where μ_0 is the vacuum permeability and Z is surface impedance of the earth which depends on the conductivity structure of the earth and on the angular frequency ω.

In a previous study about GIC in China, Liu et al. (2009b) used a uniform half-space model for the earth. However, one-dimensional layered earth models are more accurate descriptions for the real situations. Figure 2 shows a layered earth model which contains n layers with conductivities σ_1, σ_2, …, σ_n and thicknesses h_1, h_2, …, $h_n \to \infty$.

The thickness of the bottom layer is $h_n \to \infty$, and $E_x = 0$ and $B_y = 0$ when $z \to \infty$. Hence the impedance at the top of the layer of the nth layer is

$$Z_n = \mu_0 \frac{E_x}{B_y} = \frac{j\omega\mu_0}{k_n} = \sqrt{\frac{j\omega\mu_0}{\sigma_n}}, \tag{3}$$

where k_n is the propagation constant given by $k_n = \sqrt{j\omega\mu_0\sigma_n}$. The impedance at the top of the layer within the mth layer ($m = 1, 2, \ldots, n-1$) can be expressed as

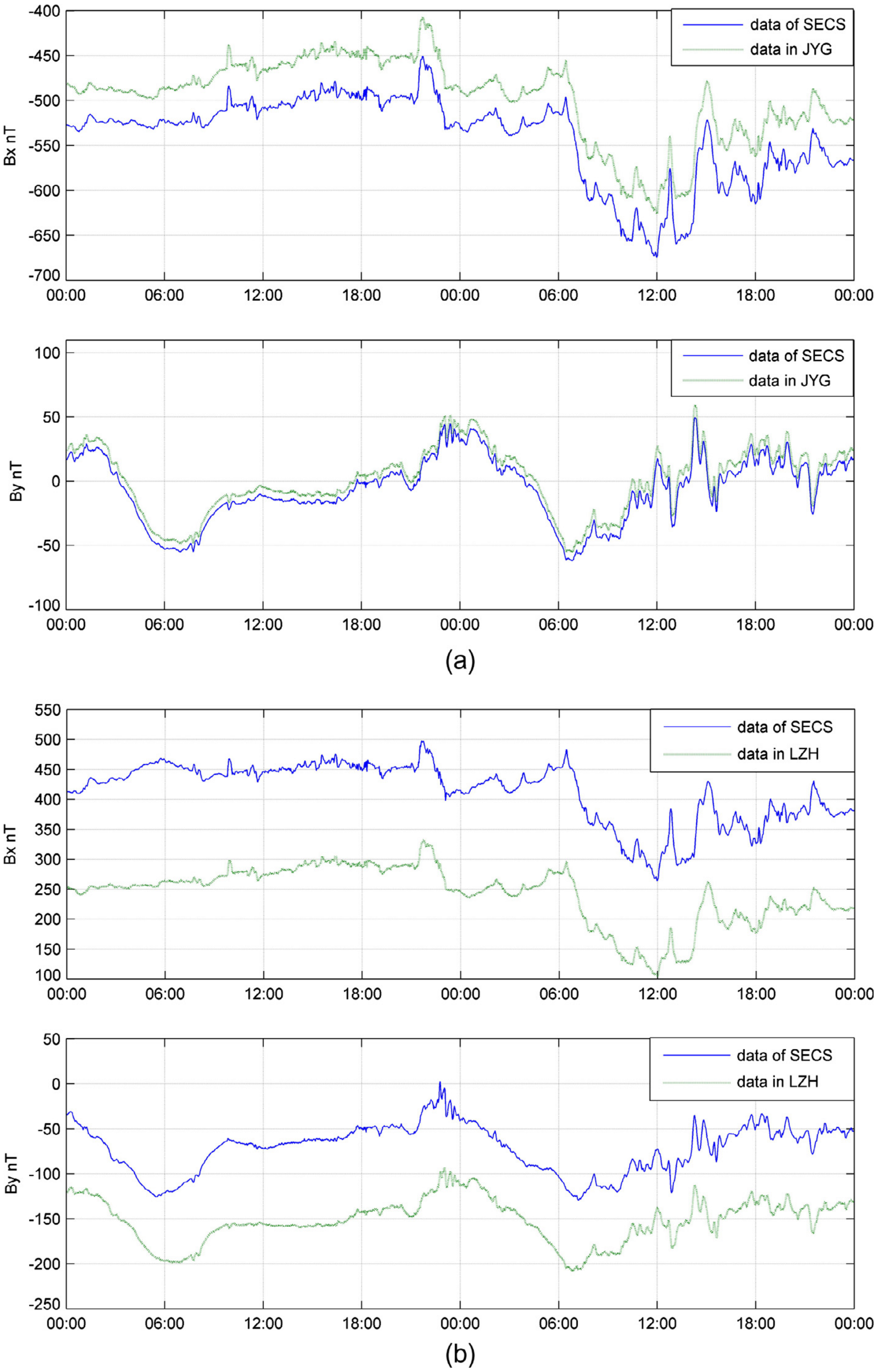

Fig. 4. Measured magnetic data and the SECS-derived magnetic data on 29–30 May 2005. The horizontal axis is the UT time in hours (a) magnetic data from JYG observatory and the SECS-derived magnetic data for Jiuquan substation and (b) magnetic data from LZH observatory and the SECS-derived magnetic data for Yongdeng substation.

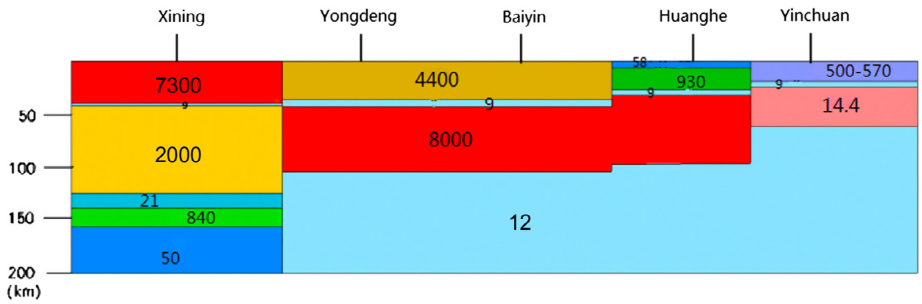

Fig. 5. Resistivity for the section Xining-Yinchuan along 750 kV power transmission lines.

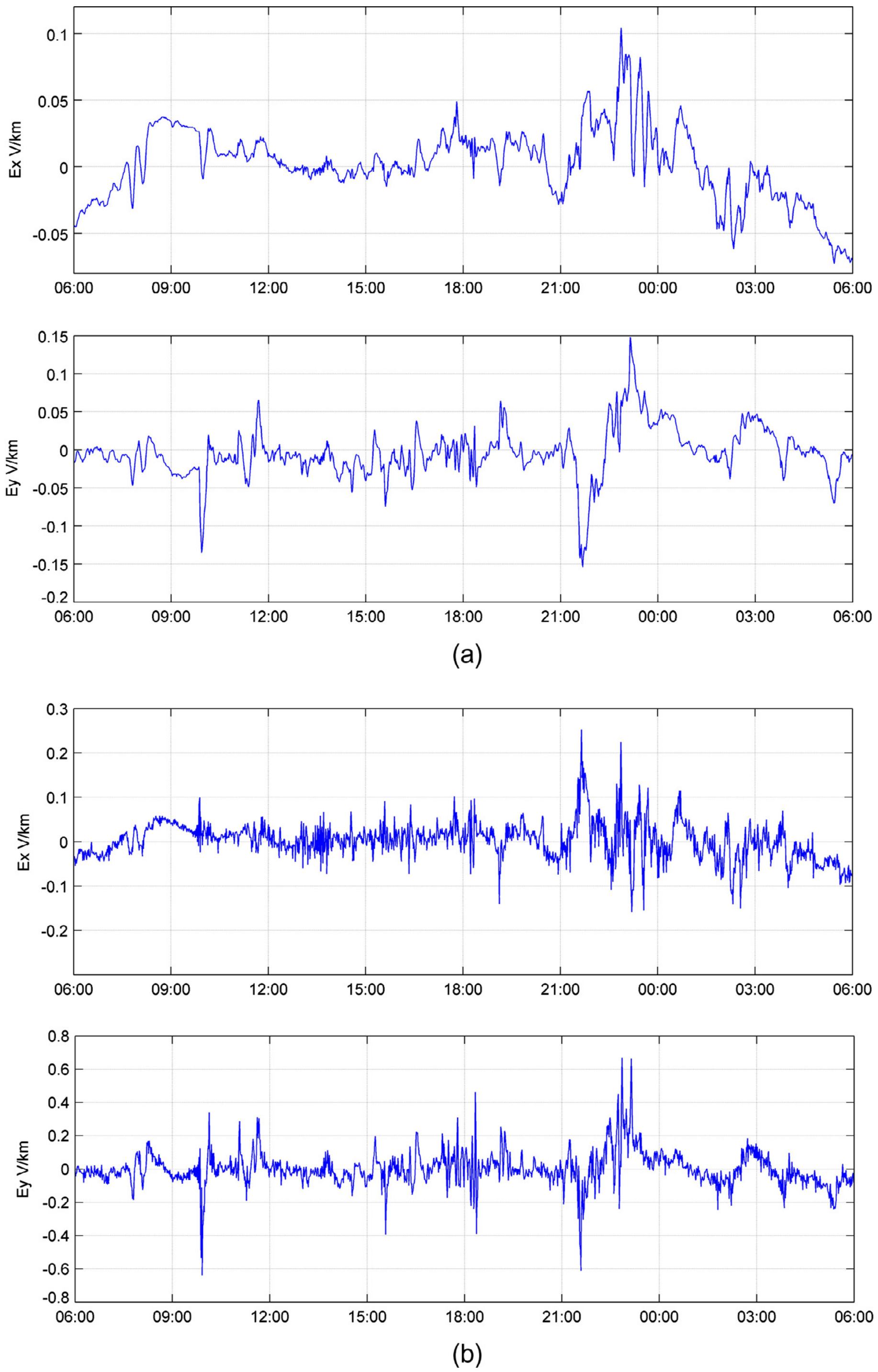

Fig. 6. Calculated geoelectric fields at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) E-Jiuquan and (b) E-Yongdeng.

$$Z_m = Z_{0m} \frac{1 - L_{m+1} e^{-2k_m h_m}}{1 + L_{m+1} e^{-2k_m h_m}} \tag{4}$$

where $k_m = \sqrt{j\omega\mu_0\sigma_m}$ and $Z_{0m} = \frac{jw\mu_0}{k_m}$ and $L_{m+1} = \frac{Z_{0m}-Z_{m+1}}{Z_{0m}+Z_{m+1}}$.

In the model, the bottom of mth layer is the top of $(m + 1)$th layer, so equation (4) can be seen as a recursive formula for the impedance at the top of each layer, through which we can calculate the surface impedance of the Earth Z. The geoelectric field in frequency domain can be calculated from geomagnetic data according to equations (1) and (2). Then the result has to be inverse Fourier transformed back to the time domain.

3.2. Calculating GIC

The frequencies of GIC are very low from the view point of power systems. Thus the GIC can be treated as a direct current. The effect of the geoelectric field on a power grid is equivalent to a set of voltage sources in the transmission lines between the substations. The value of the voltage is the integral of the electric field along the line, i.e.:

$$V_{AB} = \int_A^B \vec{E} \cdot \overleftarrow{\mathrm{d}l}\,. \tag{5}$$

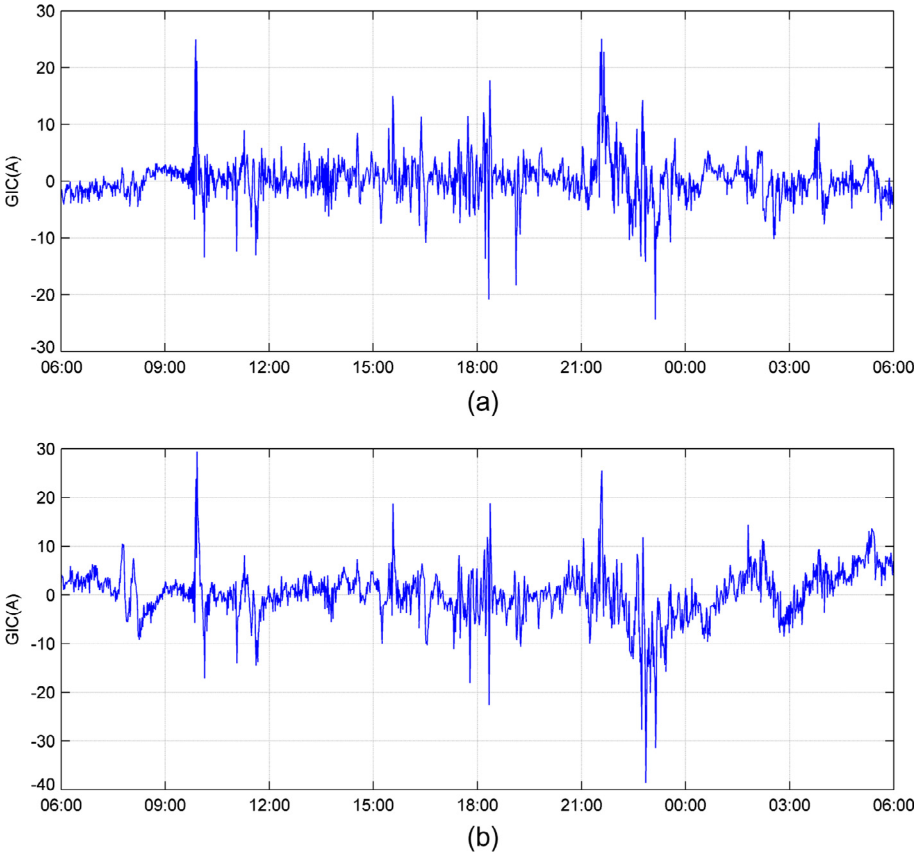

Fig. 7. Calculated GIC at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) calculated GIC at Jiuquan substation and (b) calculated GIC at Youngdeng substation.

If the geoelectric field is uniform, the integrals are independent of the paths. Therefore equation (5) can be simplified to

$$V_{AB} = L_{AB}(E_x \sin\theta + E_y \cos\theta) \tag{6}$$

Where L_{AB} is the direct distance between nodes A and B; θ is the "compass angles" i.e. clockwise from geographic North.

The GIC flowing from the power grid to the earth can be expressed as a column matrix **I**, which has the following formula (e.g., Pirjola & Lehtinen 1985)

$$\mathbf{I} = (\mathbf{1} + \mathbf{YZ})^{-1}\mathbf{J}, \tag{7}$$

where **1** is a unit (identity) matrix; **Y** and **Z** are the network admittance matrix and the earthing impedance matrix respectively. The elements of column matrix **J** are defined by

$$J_i = \sum_{j=1, j\neq i}^{N} \frac{V_{ij}}{R_{ij}}. \tag{8}$$

The matrix **J** gives the GIC between the power grid and the earth in the case of ideal groundings, i.e. the grounding resistances are zero making **Z** a zero matrix.

4. Modeling GIC in Chinese Northwest 750 kV power grid

The problem of GIC should be considered more serious in the Chinese Northwest 750 kV power grid because of the high voltage implying low transmission line resistances and because of the low earth conductivity increasing geoelectric field values. The power grid (shown in Fig. 3) for which GIC calculations are made in this paper is mainly located in the Gansu Province in the Northwest of China. We ignore the lower voltage part connected to the 750 kV power grid when modeling the GIC, because the resistances of that part are much larger, and so it is considered to have little influence on GIC flowing in the 750 kV system.

4.1. Geoelectric field calculation

We use data of the geomagnetic storm on 29–30 May 2005. The power grid is very large, extending more than 2 000 km in an east-west direction and 1 500 km in a North-South direction, so the geomagnetic variations cannot be considered to be the same all over the network. The magnetic data from four geomagnetic observatories, whose locations are shown in Figure 3 and in Table 1, are used to calculate the geoelectric field. The local magnetic data are interpolated by using the spherical elementary current systems (SECS) method (Amm 1997). The method uses geomagnetic field data to inverse the ionosphere equivalent current according to which the geomagnetic field data of every location can be calculated. Therefore the interpolation of magnetic data at different locations during a storm can be acquired. As examples, Figure 4a shows the measured data from JYG and the SECS-derived magnetic data for Jiuquan Substation, and Figure 4b shows the measured data from LZH and the SECS-derived magnetic data for Yongdeng Substation on 29–30 May 2005. It can be seen that the differences between measured magnetic data and the SECS-derived

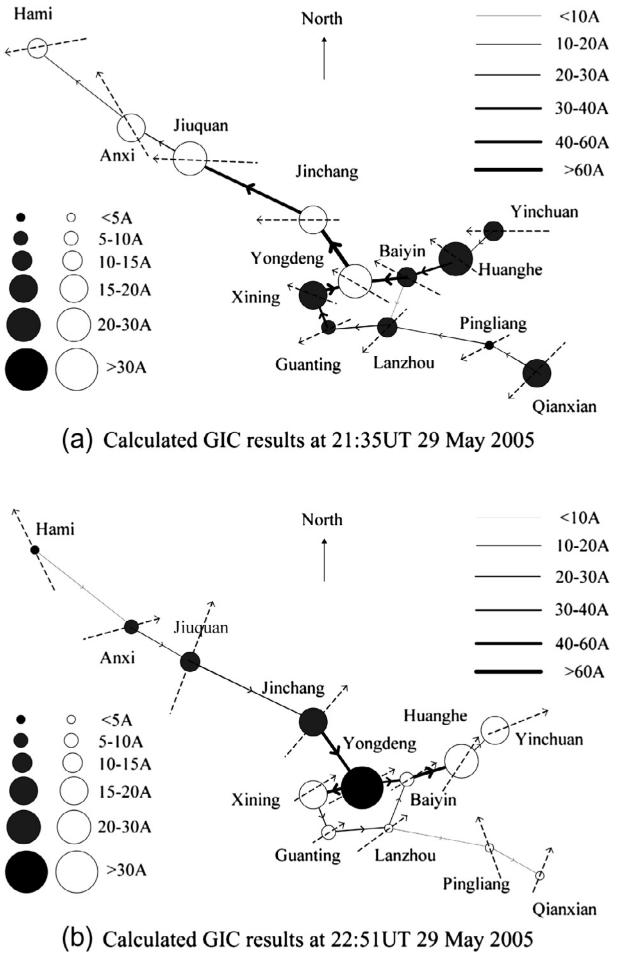

Fig. 8. Snapshots at 21:35 on 29 May 2005 (a) and at 22:51UT on 29 May 2005 (b) of calculated GIC at different sites of the Chinese Northwest 750 kV power grid. The solid circle represents that the GIC flow into the power network from ground, the hollow one means that GIC flow into the ground. The dashed line with an arrow represents the direction of electric field at that substation.

data are little except for the base line values which have no effect on the induced electric fields.

The earth conductivities are quite different across the power grid considered, so the geoelectric field values are calculated segment by segment according to the local magnetic data and the local layered earth model. In other words, we utilize the piecewise layered earth model. The earth resistivity in the region where the Chinese Northwest 750 kV power grid is located was provided by Prof. Liu Guo-Xing, a geologist at the Jilin University (private communication). Figure 5 shows a section of the earth resistivity in Ω·m from Xining to Yinchuan along the 750 kV power lines (see Fig. 3). The resistances of some places are given within a range such as 500–570 at Yinchuan in Figure 5. The upper limit values were used to calculate the induced electric fields because they stand for the most disadvantageous situation to the power grid.

As mentioned, the geoelectric fields have been calculated all over the Chinese Northwest 750 kV system based on the Piecewise layered earth models during the geomagnetic storm on 29–30 May 2005. As examples, Figure 6 shows the geoelectric field at Jiuquan and Yongdeng (whose locations are shown in Fig. 3). Our calculation results indicate that the largest E_x value is 0.36 V/km and the largest E_y value is 0.668 V/km in the area of the Northwest 750 kV grid during the geomagnetic storm considered. It is also shown by Figure 6 that the electric fields calculated for Yongdeng and Jiugan are quite different because the Earth conductivity at Yongdeng is much lower than that at Jiuquan.

4.2. GIC calculation

The GIC through all neutral points of the transformers to the Earth and in all transmission lines of the Chinese Northwest 750 kV network have been calculated. Figure 7 shows the GIC through two typical substations: Jiuquan and Yondeng (also referred to in Fig. 6). The largest GIC at Jiuquan is 25.08 A/phase at 21:35 UT on 29 May 2005, and the largest GIC at Yongdeng is 38.63 A/phase at 22:51 UT on 29 May 2005.

As snapshots, Figure 8 shows the GIC through every node and line at 21:35 UT (panel a) and at 22:51UT (panel b) on 29 May 2005 when the GIC through some of the nodes reach their peaks. It can be seen that the largest GIC through a neutral point is 38.63 A/phase, which is obtained at theYongdeng substation at 22:51 as already mentioned above (see also Fig. 7). The peak GIC through a transmission line is 68.84 A/phase, which occurs in the line from Yongdeng to Jinchang at 21:35 UT. It should be note that there is one single-phase transformer bank in a 750 kV substation except Guanting and Yinchuan where the number of transformer banks is two.

5. Conclusions

The high-voltage power grid in China may experience large GIC during geomagnetic storms, which has been concluded from monitoring the current through the neutral point at Ling'ao nuclear power plant. The GIC in the Chinese Northwest 750 kV power grid during a specific geomagnetic storm have been modeled based on calculating the geoelectric field using the piecewise layered earth models. It can be seen from the results that some sites are sensitive to geomagnetic storms, and the magnitude of GIC can be quite large (> 30 A/phase) during strong geomagnetic storms. Our studies thus clearly demonstrate that GIC are not only a high-latitude problem but networks in middle and low latitudes can be impacted as well. Factors increasing GIC risks in China include the large size of the power network, the small resistances of the transmission lines, and the high resistivity of the earth.

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Preprint for Space Weather Journal (2014)

Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment

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Abstract. Geomagnetically induced currents are known to induce disturbances in the electric power grid. Here, we perform a statistical analysis of 11,242 insurance claims from 2000 through 2010 for equipment losses and related business interruptions in North-American commercial organizations that are associated with damage to, or malfunction of, electrical and electronic equipment. We find that claims rates are elevated on days with elevated geomagnetic activity by approximately 20% for the top 5%, and by about 10% for the top third of most active days ranked by daily maximum variability of the geomagnetic field. When focusing on the claims explicitly attributed to electrical surges (amounting to more than half the total sample), we find that the dependence of claims rates on geomagnetic activity mirrors that of major disturbances in the U.S. high-voltage electric power grid. The claims statistics thus reveal that large-scale geomagnetic variability couples into the low-voltage power distribution network and that related power-quality variations can cause malfunctions and failures in electrical and electronic devices that, in turn, lead to an estimated 500 claims per average year within North America. We discuss the possible magnitude of the full economic impact associated with quality variations in electrical power associated with space weather.

1. Introduction

Large explosions that expel hot, magnetized gases on the Sun can, should they eventually envelop Earth, effect severe disturbances in the geomagnetic field. These, in turn, cause geomagnetically induced currents (GICs) to run through the surface layers of the Earth and through conducting infrastructures in and on these, including the electrical power grids. The storm-related GICs run on a background of daily variations associated with solar (X)(E)UV irradiation that itself is variable through its dependence on both quiescent and flaring processes.

The strongest GIC events are known to have impacted the power grid on occasion [see, e.g., *Kappenman et al.*, 1997; *Boteler et al.*, 1998; *Arslan Erinmez et al.*, 2002; *Kappenman*, 2005; *Wik et al.*, 2009]. Among the best-known of such impacts is the 1989 Hydro-Québec blackout [e.g., *Bolduc*, 2002; *Béland and Small*, 2004]. Impacts are likely strongest at mid to high geomagnetic latitudes, but low-latitude regions also appear susceptible [*Gaunt*, 2013].

The potential for severe impacts on the high-voltage power grid and thereby on society that depends on it has been assessed in studies by government, academic, and insurance industry working groups [e.g., *Space Studies Board*, 2008; *FEMA*, 2010; *Kappenman*, 2010; *Hapgood*, 2011; *JASON*, 2011]. How costly such potential major grid failures would be remains to be determined, but impacts of many billions of dollars have been suggested [e.g., *Space Studies Board*, 2008; *JASON*, 2011].

Non-catastrophic GIC effects on the high-voltage electrical grid percolate into financial consequences for the power market [*Forbes and St. Cyr*, 2004, 2008, 2010] leading to price variations on the bulk electrical power market on the order of a few percent [*Forbes and St. Cyr*, 2004].

Schrijver and Mitchell [2013] quantified the susceptibility of the U.S. high-voltage power grid to severe, yet not extreme, space storms, leading to power outages and power-quality variations related to voltage sags and frequency changes. They find, "with more than 3σ significance, that approximately 4% of the disturbances in the US power grid reported to the US Department of Energy are attributable to strong geomagnetic activity and its associated geomagnetically induced currents."

The effects of GICs on the high-voltage power grid can, in turn, affect the low-voltage distribution networks and, in principle, might impact electrical and electronic systems of users of those regional and local networks. A first indication that this does indeed happen was reported on in association with tests conducted by the Idaho National Laboratory (INL) and the Defense Threat Reduction Agency (DTRA). They reported [*Wise and Benjamin*, 2013] that "INL and DTRA used the lab's unique power grid and a pair of 138kV core form, 2 winding substation transformers, which had been in-service at INL since the 1950s, to perform the first full-scale testing to replicate conditions electric utilities could experience from geomagnetic disturbances." In these experiments, the researchers could study how the artificial GIC-like currents resulted in harmonics on the power lines that can affect the power transmission and distribution equipment. These "tests demonstrated that geomagnetic-induced harmonics are strong enough to penetrate many power line filters and cause temporary resets to computer power supplies and disruption to electronic equipment, such as uninterruptible power supplies".

In parallel to that experiment, we collected information on insurance claims submitted to Zurich North-America (NA) for damage to, or outages of, electrical and electronic systems from all types of industries for a comparison with geomagnetic variability. Here, we report on the results of a retrospective cohort exposure analysis of the impact of geomagnetic variability on the frequency of insurance claims. In this analysis, we contrast insurance claims frequencies on "high-exposure" dates (i.e., dates of high geomagnetic activity) with a control sample of "low-exposure" dates (i.e., dates with essentially quiescent space weather conditions), carefully matching each high-exposure date to a

[1]Lockheed Martin Advanced Technology Center, Palo Alto, CA, USA
[2]Zurich Services Corporation, Schaumburg, IL, USA
[3]Space Weather Prediction Center, Boulder, CO, USA

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control sample nearby in time so that we may assume no systematic changes in conditions other than space weather occurred between the exposure dates and their controls (thus compensating for seasonal weather changes and other trends and cycles).

For comparison purposes we repeat the analysis of the frequency of disturbances in the high-voltage electrical power grid as performed by *Schrijver and Mitchell* [2013] for the same date range and with matching criteria for threshold setting and for the selection of the control samples. In Section 1 we describe the insurance claim data, the metric of geomagnetic variability used, and the grid-disturbance information. The procedure to test for any impacts of space weather on insurance claims and the high-voltage power grid is presented and applied in Section 3. We summarize our conclusions in Section 4 where we also discuss the challenges in translating the statistics on claims and disturbances into an economic impact.

2. Data

2.1. Insurance claim data

We compiled a list of all insurance claims filed by commercial organizations to Zurich NA relating to costs incurred for electrical and electronic systems for the 11-year interval from 2000/01/01 through 2010/12/31. Available for our study were the date of the event to which the claim referred, the state or province within which the event occurred, a brief description of the affected equipment, and a top-level assessment of the probable cause. Information that might lead to identification of the insured parties was not disclosed.

Zurich NA estimates that it has a market share of approximately 8% in North America for policies covering commercially-used electrical and electronic equipment and contingency business interruptions related to their failure to function properly during the study period. Using that information as a multiplier suggests that overall some 12,800 claims are filed per average year related to electrical/electronic equipment problems in North-American businesses. The data available for this study cannot reveal impacts on uninsured or self-insured organizations or impacts in events of which the costs fall below the policy deductable.

The 11-year period under study has the same duration as that characteristic of the solar magnetic activity cycle. Fig. 1 shows that the start of this period coincides with the maximum in the annual sunspot number for 2000, followed by a decline into an extended minimum period in 2008 and 2009, ending with the rise of sunspot number into the start of the next cycle.

The full sample of claims, regardless of attribution, for which an electrical or electronic system was involved includes 11,242 entries. We refer to this complete set as set A.

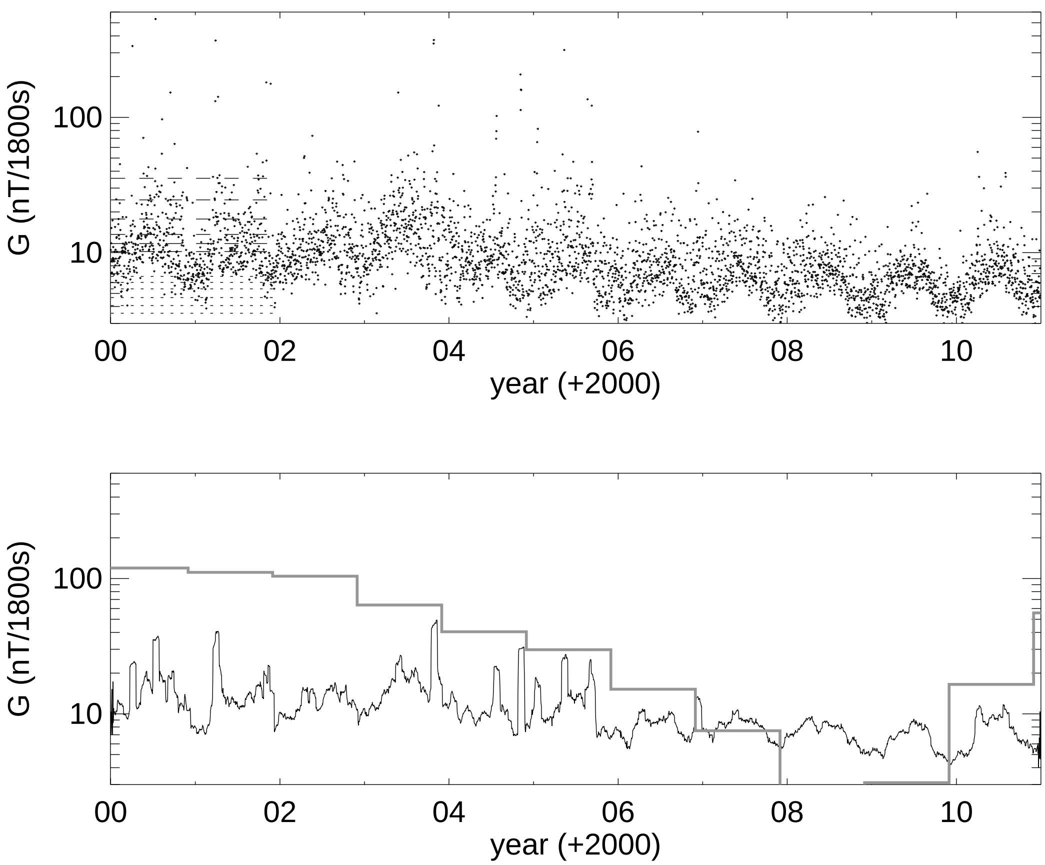

Figure 1. *Daily values $G \equiv max(|dB/dt|)$ based on 30-min. intervals (dots; nT/1800s) characterizing geomagnetic variability for the contiguous United States versus time (in years since 2000). The 27-d running mean is shown by the solid line. The levels for the 98, 95, 90, 82, 75, and 67 percentiles of the entire sample are shown by dashed lines (sorting downward from the top value of G) and dotted lines (sorting upward from the minimum value of the daily geomagnetic variability as expressed by $G \equiv max(|dB/dt|)$). The grey histogram shows the annual mean sunspot number.*

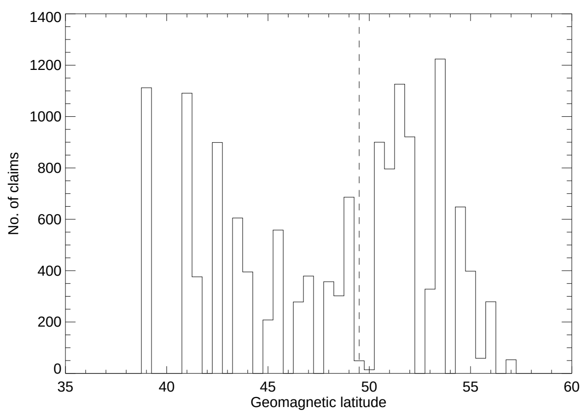

Figure 2. *Number of insurance claims sorted by geomagnetic latitude (using the central geographical location of the state) in 0.5° bins. The dashed line at 49.5° is near the median geomagnetic latitude of the sample (at 49.3°), separating what this paper refers to as high-latitude from low-latitude states.*

Claims that were attributed to causes that were in all likelihood not associated with space weather phenomena were deleted from set A to form set B (with 8,151 entries remaining after review of the Accident Narrative description of each line item). Such omitted claims included attributions to water leaks and flooding, stolen or lost equipment, vandalism or other intentional damage, vehicle damage or vehicular accidents, animal intrusions (raccoons, squirrels, birds, etc.), obvious mechanical damage, and obvious weather damage (ice storm damage, hurricane/windstorm damage, etc.). The probable causes for the events making up set B were limited to the following categories (sorted by the occurrence frequency, given in percent): Misc: Electrical surge (59%); Apparatus, Miscellaneous Electrical - Breaking (30%); Apparatus, Miscellaneous Electrical - Arcing (4.1%); Electronics - Breaking (1.6%); Apparatus, Miscellaneous Electrical - Overheating (1.4%); Transformers - Arcing (0.9%); Electronics - Arcing (0.6%); Transformers - Breaking (0.5%); Generators - Breaking (0.4%); Apparatus, Electronics - Overheating (0.3%); Generators - Arcing (0.2%); Generators - Overheating (0.2%); and Transformers - Overheating (0.1%).

Fig. 2 shows the number of claims received as a function of the mean geomagnetic latitude for the state within which the claim was recorded. Based on this histogram, we divided the claims into categories of comparable size for high and low geomagnetic latitudes along a separation at 49.°5 north geomagnetic latitude to enable testing for a dependence on proximity to the auroral zones. We note that we do not have access to information about the latitudinal distribution of insured assets, only on the claims received. Hence, we can only assess any dependence of insurance claims on latitude in a relative sense, comparing excess relative claims frequencies for claims above and below the median geomagnetic latitudes, as discussed in Sect. 3.

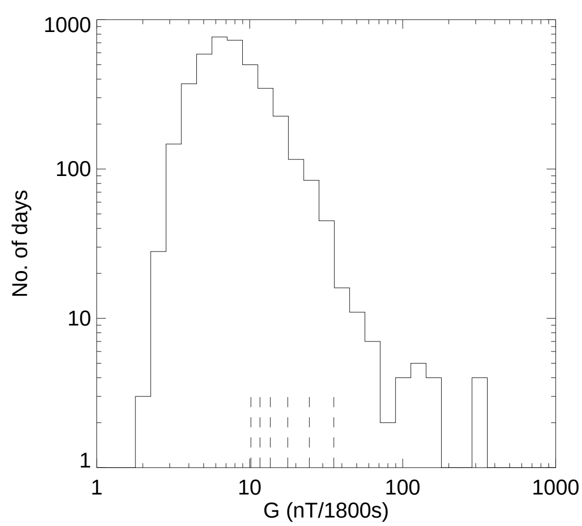

Figure 3. *Histogram of the number of days between 2000/01/01 and 2010/12/31 with values of $G \equiv max(|dB/dt|)$ in logarithmically spaced intervals as shown on the horizontal axis. The 98, 95, 90, 82, 75, and 67 percentiles (ranking G from low to high) are shown by dashed lines.*

2.2. Geomagnetic data

Geomagnetically-induced currents are driven by changes in the geomagnetic field. These changes are caused by the interaction of the variable, magnetized solar wind with the geomagnetic field and by the insolation of Earth's atmosphere that varies globally with solar activity and locally owing to the Earth's daily rotation and annual revolution in its orbit around the Sun. A variety of geomagnetic activity indices is available to characterize geomagnetic field variability [e.g., *Jursa*, 1985]. These indices are sensitive to different aspects of the variable geomagnetic-ionospheric current systems as they may differentially filter or weight storm-time variations (Dst), disturbance-daily variations (Ds), or solar quiet daily variations (known as the Sq field), and may weight differentially by (geomagnetic) latitude. Here, we are interested not in any particular driver of

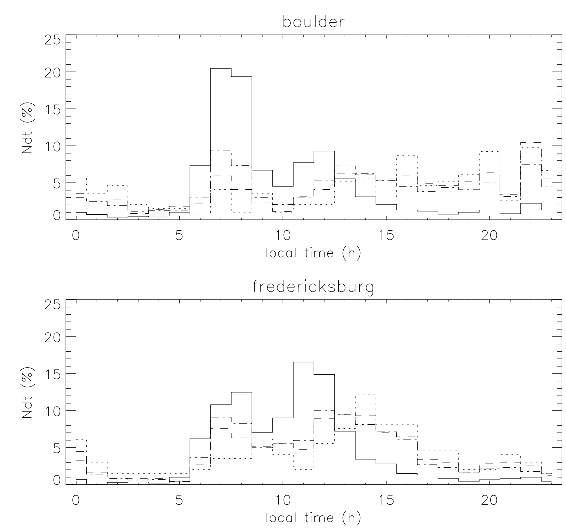

Figure 4. *Normalized histograms of the local times for which the values of $G \equiv max(|dB/dt|)$ reach their daily maximum (top: Boulder; bottom: Fredericksburg). The solid histogram shows the distribution for daily peaks for all dates with G values in the lower half of the distribution, i.e., for generally quiescent conditions. The dotted, dashed, and dashed-dotted histograms show the distributions for dates with high G values, for thresholds set at the 95, 82, and 67 percentiles of the set of values for G, respectively.*

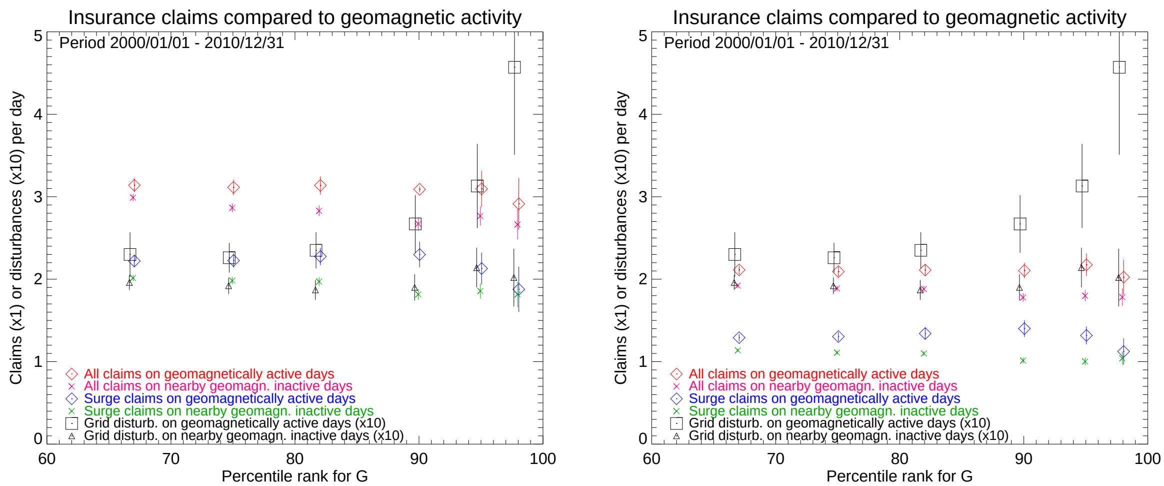

Figure 5. *Claims per day for the full sample of insurance claims (set* A *left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). Each panel shows mean incident claim frequencies* $n_i \pm \sigma_c$ *(diamonds) for the most geomagnetically active dates, specifically for the 98, 95, 90, 82, 75, and 67 percentiles of the distribution of daily values of* $G \equiv max(|dB/dt|)$ *sorted from low to high (shown with slight horizontal offsets to avoid overlap in the symbols and bars showing the standard deviations for the mean values). The asterisks show the associated claim frequencies* $n_c \pm \sigma_c$*, for the control samples. The panels also show the frequencies of reported high-voltage power-grid disturbances (diamonds and triangles for geomagnetically active dates and for control dates, respectively), multiplied by 10 for easier comparison, using the same exposure-control sampling and applied to the same date range as that used for the insurance claims.*

changes in the geomagnetic field but rather need a metric of the rate of change in the strength of the surface magnetic field as that is the primary driver of geomagnetically-induced currents.

To quantify the variability in the geomagnetic field we use the same metric as *Schrijver and Mitchell* [2013] based on the minute-by-minute geomagnetic field measurements from the Boulder (BOU) and Fredericksburg (FRD) stations (available via http://ottawa.intermagnet.org): we use these measurements to compute the daily maximum value, G, of $|dB/dt|$ over 30-min. intervals, using the mean value for the two stations. We selected this metric recognizing a need to use a more regional metric than the often-used global metrics, but also recognizing that the available geomagnetic and insurance claims data have poor geographical resolution so that a focus on a metric responsive to relatively low-order geomagnetic variability was appropriate. We chose a time base short enough to be sensitive to rapid changes in the geomagnetic field, but long enough that it is also sensitive to sustained changes over the course of over some tens of minutes. For the purpose of this study, we chose to use a single metric of geomagnetic variability, but with the conclusion of our pilot study revealing a dependence of damage to electrical and electronic equipment on space weather conditions, a multi-parameter follow up study is clearly warranted, ideally also with more information on insurance claims, than could be achieved with what we have access to for this exploratory study.

The BOU and FRD stations are located along the central latitudinal axis of the U.S.. The averaging of their measurements somewhat emphasizes the eastern U.S. as do the grid and population that uses that. Because the insurance claims use dates based on local time we compute the daily G values based on date boundaries of U.S. central time. Fig. 3 shows the distribution of values of G, while also showing the levels of the percentiles for the rank-sorted value of G used as threshold values for a series of sub-samples in the following sections.

Figure 4 shows the local times at which the maximum variations in the geomagnetic field occur during 30-min. intervals. The most pronounced peak in the distribution for geomagnetically quiet days (solid histogram) occurs around $7-8$ o'clock local time, i.e., a few hours after sunrise, and a second peak occurs around local noon. The histograms for the subsets of geomagnetically active days for which G values exceed thresholds set at 67, 82, and 95 percentiles of the sample are much broader, even more so for the Boulder station than for the Fredericksburg station. From the perspective of the present study, it is important to note that the majority of the peak times for our metric of geomagnetic variability occurs within the economically most active window from 7 to 18 hours local time; for example, at the 82-percentile of geomagnetic variability in G, 54% and 77% of the peak variability occur in that time span for Boulder and Fredericksburg, respectively.

From a general physics perspective, we note that periods of markedly enhanced geomagnetic activity ride on top of a daily background variation of the ionospheric current systes (largely associated with the "solar quiet" modulations, referred to as the Sq field) that is induced to a large extent by solar irradiation of the atmosphere of the rotating Earth, including the variable coronal components associated with active-region gradual evolution and impulsive solar flaring. We do not attempt to separate the impacts of these drivers in this study, both because we do not have information on the local times for which the problems occurred that lead to the insurance claims, and because the power grid is sensitive to the total variability in the geomagnetic field regardless of cause.

The daily G values are shown versus time in Fig. 1, along with a 27-d running mean and (as a grey histogram) the yearly sunspot number. As expected, the G value shows strong upward excursions particularly during the sunspot maximum. Note the annual modulation in G with generally lower values in the northern-hemispheric winter months than in the summer months.

2.3. Power-grid disturbances

In parallel to the analysis of the insurance claims statistics, we also analyze the frequencies of disturbances in the U.S. high-voltage power grid. *Schrijver and Mitchell* [2013] compiled a list of "system disturbances" published by the North American Electric Reliability Corporation (NERC: available since 1992) and by the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE; available since 2000). This information is compiled by NERC for a region with over 300 million electric power customers throughout the U.S.A. and in Ontario and New Brunswick in Canada, connected by more than 340,000 km of high-voltage transmission lines delivering power generated in some 18,000 power plants within the U.S. [*JASON*, 2011]. The reported disturbances include, among others, "electric service interruptions, voltage reductions, acts of sabotage, unusual occurrences that can affect the reliability of the bulk electric systems, and fuel problems." We use the complete set of disturbances reported from 2000/01/01 through 2010/12/31 regardless of attributed cause. We refer to *Schrijver and Mitchell* [2013] for more details.

3. Testing for the impact of space weather

In order to quantify effects of geomagnetic variability on the frequency of insurance claims filed for electrical and electronic equipment we need to carefully control for a multitude of variables that include trends in solar activity, the structure and operation of the power grid (including, for example, scheduled maintenance and inspection), various societal and technological factors changing over the years, as well as the costs and procedures related to the insurance industry, and, of course, weather and seasonal trends related to the insolation angle and the varying tilt of the Earth's magnetic field relative to the incoming solar wind throughout the year.

There are many parameters that may influence the ionospheric current systems, the quality and continuity of electrical power, and the malfunctioning of equipment running on electrical power. We may not presume that we could identify and obtain all such parameters, or that all power grid segments and all equipment would respond similarly to changes in these parameters. We therefore do not attempt a multi-parameter correlation study, but instead apply a retrospective cohort exposure study with tightly matched controls very similar to that applied by Schrijver and Mitchell (2013).

This type of exposure study is based on pairing dates of exposure, i.e., of elevated geomagnetic activity, with control dates of low geomagnetic activity shortly before or after each of the dates of exposure, selected from within a fairly narrow window in time during which we expect no substantial systematic variation in ionospheric conditions, weather, the operations of the grid, or the equipment powered by the grid. Our results are based on a comparison of claims counts on exposure dates relative to claims counts on matching sets of nearby control dates. This minimizes the impacts of trends (including "confounders") in any of the potential factors that affect the claims statistics or geomagnetic variability, including the daily variations in quiet-Sun irradiance and the seasonal variations as Earth orbits the Sun, the solar cycle, and the structure and operation of the electrical power network. This is a standard method as used in, e.g., epidemiology. We refer to Wacholder et al. (1992, and references therein) for a discussion on this method particularly regarding ensuring of time comparability of the "exposed" and control samples, to Schulz and Grimes (2002) for a discussion on the comparison of cohort studies as applied here versus case-control studies, and to Grimes and Schulz (2005) for a discussion of selection biases in samples and their controls (specifically their example on pp. 1429-1430).

We define a series of values of geomagnetic variability in order to form sets of dates including different ranges of exposure, i.e., of geomagnetic variability, so that each high exposure date is matched by representative low exposure dates as controls. We create exposure sets by selecting a series of threshold levels corresponding to percentages of all dates with the most intense geomagnetic activity as measured by the metric G. Specifically, we determined the values of G for which geomagnetic activity, sorted from least active upward, includes 67%, 75%, 82%, 90%, 95%, and 98% of all dates in our study period. For each threshold value we selected the dates with G exceeding that threshold (with possible further selection criteria as described below). For each percentile set we compute the mean daily rate of incident claims, n_i, as well as the standard deviation on the mean, σ_i, as determined from the events in the day-by-day claims list.

In order to form tightly matched control samples for low "exposure", we then select 3 dates within a 27-d period centered on each of the selected high-activity days. The 27-d period, also known as the Bartels period, is that characteristic of a full rotation of the solar large-scale field as viewed from the orbiting Earth; G values within that period sample geomagnetic variability as induced during one full solar rotation. This window for control sample selection is tighter than that used by *Schrijver and Mitchell* [2013] who used 100-day windows centered on dates with reported grid disturbances. For the present study we selected a narrower window to put even stronger limits on the potential effects of any possible long-term trends in factors that might influence claims statistics or geomagnetic variability. We note that there is no substantive change in our main conclusions for control windows at least up to 100 days in duration.

The three dates selected from within this 27-d interval are those with the lowest value of G smoothed with a 3-day running mean. We determine the mean claim rate, n_c, for this control set and the associated standard deviation in the mean, σ_c.

Fig. 5 shows the resulting daily frequency of claims and the standard deviations in the mean, $n_i \pm \sigma_i$, for the selected percentiles, both for the full sample A (left panel) and for sample B (right panel) from which claims were omitted that were attributed to causes not likely associated directly or indirectly with geomagnetic activity. For all percentile sets we see that the claim frequencies n_i on geomagnetically active days exceed the frequencies n_c for the control dates.

The frequency distributions of insurance claims are not Poisson distributions, as can be seen in the example in Fig. 6 (left panel): compared to a Poisson distribution of the same mean, the claims distributions on geomagnetically active dates, $N_{\rm B,a,75}$ and for control days, $N_{\rm B,c,75}$, are skewed to have a peak frequency at lower numbers and a raised tail at higher numbers; a Kolmogorov-Smirnov (KS) test suggests that the probability that $N_{\rm B,c,75}$ is consistent with a Poisson distribution with the same mean is 0.01 for this example. The elevated tail of the distribution relative to a Poisson distribution suggests some correlation between claims events, which is of interest from an actuarial perspective as it suggests a nonlinear response of the power system to space weather that we cannot investigate further here owing to the signal to noise ratio of the results given our sample.

For the case shown in Fig. 6 for the 25% most geomagnetically active dates in set B, a KS test shows that the probability that $N_{\rm B,a,75}$ and $N_{\rm B,c,75}$ are drawn from the same parent distribution is of order 10^{-14}, i.e. extremely unlikely.

The numbers that we are ultimately interested in are the excess frequencies of claims on geomagnetically active

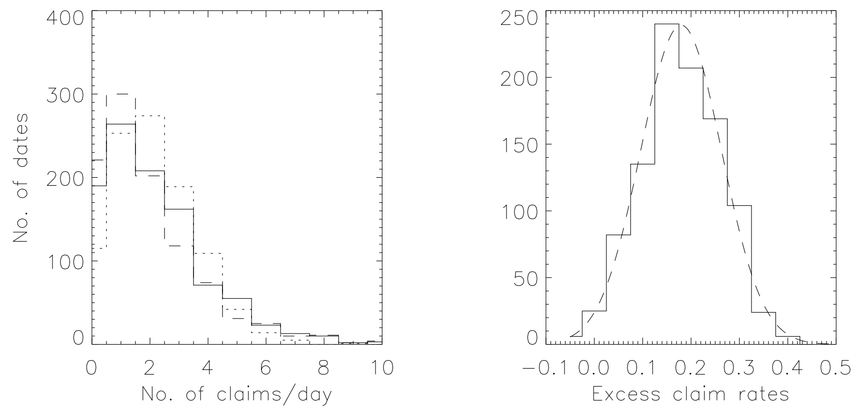

Figure 6. *(left) Distribution of the number of claims per geomagnetically active day for set* B *for the top 25% of G values (solid) compared to that for the distribution of control dates (divided by 3 to yield the same total number of dates; dashed). For comparison, the expected histogram for a random Poisson distribution with the same mean as that for the geomagnetically active days is also shown (dotted). (right) Distribution (solid) of excess daily claim frequencies during geomagnetically active days (defined as in the left panel) over those on control dates determined by repeated random sampling from the observations (known as the bootstrap method), compared to a Gaussian distribution (dashed) with the same mean and standard deviation.*

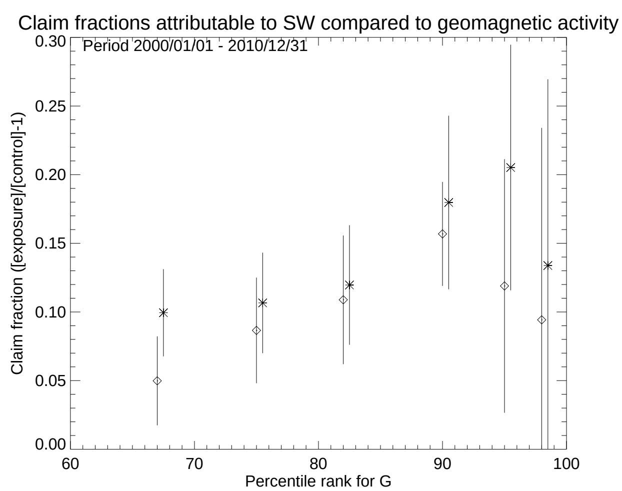

Figure 7. *Relative excess claim frequencies statistically associated with geomagnetic activity (difference between claim frequencies on geomagnetically active dates and the frequencies on control dates as shown in Fig. 5, i.e., $(n_i - n_c)/n_c$) for the full sample (A; diamonds) and for the sample (B; asterisks) from which claims were removed attributable to apparently non-space-weather related causes.*

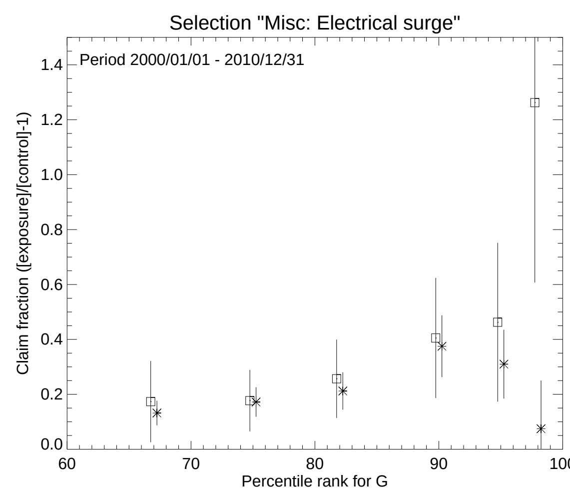

Figure 8. *Same as Fig. 7 but for sample* B *limited to those claims attributed to "Misc.: Electrical surge" (asterisks) (for 57% of the cases in that sample), compared to the fraction of high-voltage power-grid disturbances statistically associated with geomagnetic activity (squares).*

dates over those on the control dates, and their uncertainty. For the above data set, we find and excess daily claims rate of $(n_{\rm B,i} - n_{\rm B,c}) \pm \sigma_{\rm B} = 0.20 \pm 0.08$. The uncertainty $\sigma_{\rm B}$ is in this case determined by repeated random sampling of the claims sample for exposure and control dates, and subsequently determining the standard deviation in a large sample of resulting excess frequencies (using the so-called bootstrap method). The distribution of excess frequencies (shown in the righthand panel of Fig. 6) is essentially Gaussian, so that the metric of the standard deviation gives a useful value to specify the uncertainty. We note that the value of $\sigma_{\rm B}$ is comparable to the value $\sigma_{a,c} = (\sigma_{\rm a}^2 + \sigma_{\rm b}^2)^{1/2}$ derived by combining the standard deviations for the numbers of claims per day for geomagnetically active dates and the control dates, which in this case equals $\sigma_{a,c} = 0.07$. Thus, despite the skewness of the claim count distributions relative to a Poisson distribution as shown in the example in the left panel of Fig. 6, the effect of that on the uncertainty in the excess claims rate is relatively small. For this reason, we show the standard deviations on the mean frequencies in Figs. 5-10 as a useful visual indicator of the significance of the differences in mean frequencies.

Fig. 7 shows the relative excess claims frequencies, i.e., the relative differences $r_e = (n_i - n_c)/n_c$ between the claim frequencies on geomagnetically active dates and those on the control dates, thus quantifying the claim fraction statistically associated with elevated geomagnetic activity. The uncertainties shown are computed as $\sigma_e =$

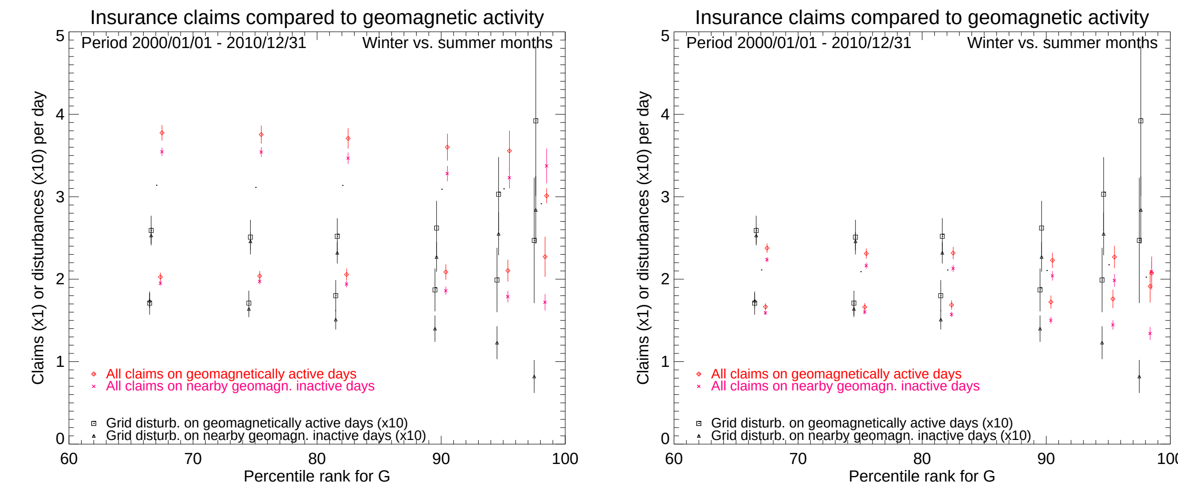

Figure 9. *As Fig. 5 but separating the winter half year (October through March) from the summer half year (April through September), for the full sample of insurance claims (set* A*, left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). Values for the summer months are shown offset slightly towards the left of the percentiles tested (98, 95, 90, 82, 75, and 67) while values for the winter months are offset to the right. Values for the winter season are systematically higher than those for summer months.*

$(\sigma_i^2/n_i^2 + \sigma_c^2/n_c^2)^{1/2}\, r_e$, i.e., using the approximation of normally distributed uncertainties, warranted by the arguments above. We note that the relative rate of claims statistically associated with space weather is slightly higher for sample B than for the full set A consistent with the hypothesis that the claims omitted from sample A to form sample B were indeed preferentially unaffected by geomagnetic activity. Most importantly, we note that the rate of claims statistically associated with geomagnetic activity increases with the magnitude of that activity.

About 59% of the claims in sample B attribute the case of the problem to "Misc.: Electrical surge", so that we can be certain that some variation in the quality or continuity of electrical power was involved. Fig. 8 shows the relative excess claims rate $(n_i - n_c)/n_c$ as function of threshold for geomagnetic activity. We compare these results with the same metric, based on identical selection procedures, for the frequency of disturbances in the high-voltage power grid (squares). We note that these two metrics, one for interference with commercial electrical/electronic equipment and one for high-voltage power, agree within the uncertainties, with the possible exception of the infrequent highest geomagnetic activity (98 percentile) although there the statistical uncertainties on the mean frequencies are so large that the difference is less than 2 standard deviations in the mean values.

To quantify the significance of the excess claims frequencies on geomagnetically active days we perform a non-parametric Kolmogorov-Smirnov (KS) test of the null hypothesis that the claims events on active and on control days could be drawn from the same parent sample. The resulting p values from the KS test, summarized in Table 1, show that it is extremely unlikely that our conclusion that geomagnetic activity has an impact on insurance claims could be based on chance, except for the highest percentiles

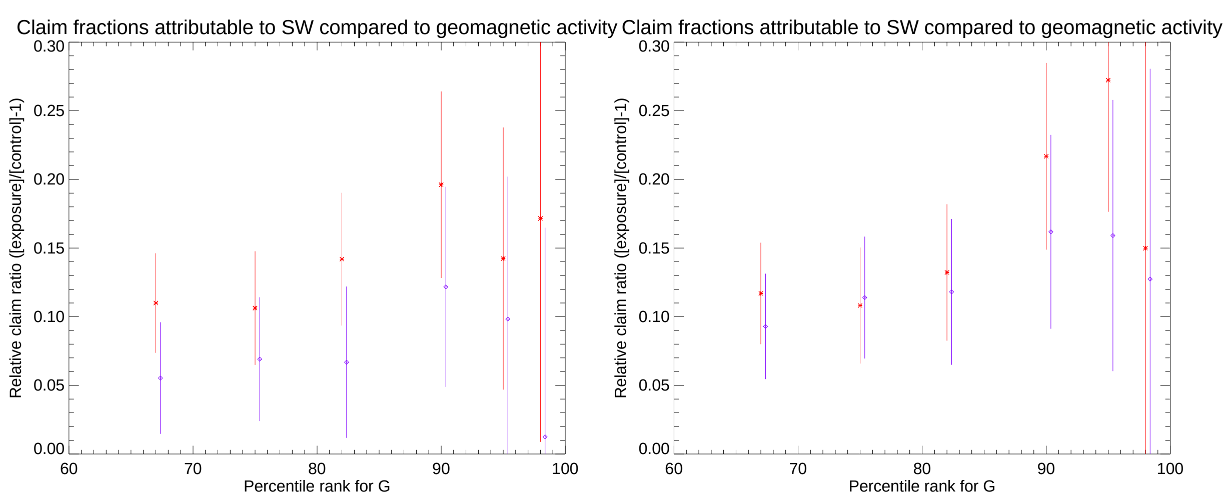

Figure 10. *Relative excess claim frequencies $(n_i - n_c)/n_i$ on geomagnetically active dates relative to those on control dates for geomagnetic latitudes below $49.^\circ5$ N (asterisks, red) compared to those for higher latitudes (diamonds, purple; offset slightly to the right) for the percentiles tested (98, 95, 90, 82, 75, and 67). The lefthand panel shows the results for the full sample (A), and the righthand panel shows these for sample B from which apparently non-space-weather related events were removed (see Section 2.1).*

Table 1. Probability (p) values based on a Kolmogorov-Smirnov test that the observed sets of claims numbers on geomagnetically active dates and on control dates are drawn from the same parent distribution, for date sets with the geomagnetic activity metric G exceeding the percentile threshold in the distribution of values.

Percentile	All claims		Attr. to electr. surges	
	set A	set B	set A	set B
67	$2.\times10^{-10}$	$2.\times10^{-19}$	$1.\times10^{-27}$	0
75	$3.\times10^{-7}$	$4.\times10^{-14}$	$8.\times10^{-20}$	$4.\times10^{-35}$
82	0.0004	$2.\times10^{-7}$	$1.\times10^{-13}$	$6.\times10^{-24}$
90	0.010	0.0002	$1.\times10^{-7}$	$8.\times10^{-13}$
95	0.05	0.013	0.0001	$2.\times10^{-7}$
98	0.33	0.06	0.003	0.0001

in which the small sample sizes result in larger uncertainties. We note that the p values tend to decrease when we eliminate claims most likely unaffected by space weather (contrasting set A with B) and when we limit either set to events attributed to electrical surges: biasing the sample tested towards issues more likely associated with power-grid variability increases the significance of our findings that there is an impact of space weather.

Fig. 9 shows insurance claims differentiated by season: the frequencies of both insurance claims and power-grid disturbances are higher in the winter months than in the summer months, but the excess claim frequencies statistically associated with geomagnetic activity follow similar trends as for the full date range. The same is true when looking at the subset of events attributed to surges in the low-voltage power distribution grid.

Figure 11 shows a similar diagram to that on left-hand side of Fig. 9, now differentiating between the equinox periods and the solstice periods. Note that although the claims frequencies for the solstice periods are higher than those for the equinox periods, that difference is mainly a consequence of background (control) frequencies: the fractional excess frequencies on geomagnetically active days relative to the control dates are larger around the equinoxes than around the solstices.

Fig. 10 shows the comparison of claim ratios of geomagnetically active dates relative to control dates for states with high versus low geomagnetic latitude, revealing no significant contrast (based on uncertainties computed as described above for Fig. 7).

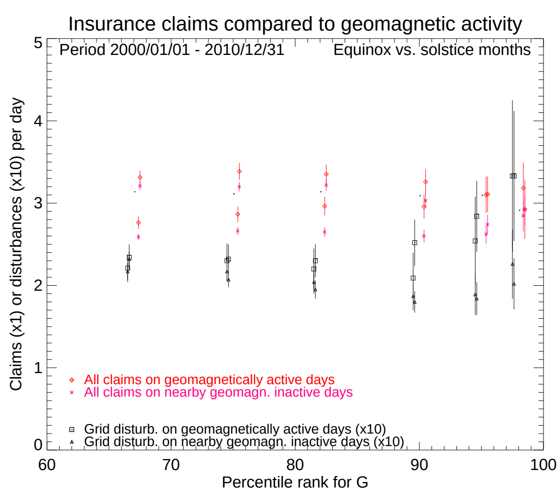

Figure 11. *As Fig. 9 but separating the months around the equinoxes (February-April and August-October) from the complementing months around the solstices, for the full sample of insurance claims (set* A*). Values for the equinox periods are shown offset slightly towards the left of the percentiles tested (98, 95, 90, 82, 75, and 67) while values for the solstice months are offset to the right. Mean claims frequencies for the solstice periods are systematically higher than those for equinox periods, but the frequencies for high-G days in excess of the control sample frequencies is slightly larger around the equinoxes than around the solstices.*

4. Discussion and conclusions

We perform a statistical study of North-American insurance claims for malfunctions of electronic and electrical equipment and for business interruptions related to such malfunctions. We find that there is a significant increase in claim frequencies in association with elevated variability in the geomagnetic field, comparable in magnitude to the increase in occurrence frequencies of space weather-related disturbances in the high-voltage power grid. In summary:

- The fraction of insurance claims statistically associated with geomagnetic variability tends to increase with increasing activity from about $5-10\%$ of claims for the top third of most active days to approximately 20% for the most active few percent of days.
- The overall fraction of all insurance claims statistically associated with the effects of geomagnetic activity is $\approx 4\%$. With a market share of about 8% for Zurich NA in this area, we estimate that some 500 claims per year are involved overall in North America.
- Disturbances in the high-voltage power grid statistically associated with geomagnetic activity show a comparable frequency dependence on geomagnetic activity as do insurance claims.
- We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude.

For our study, we use a quantity that measures the rate of change of the geomagnetic field regardless of what drives that. Having established an impact of space weather on users of the electric power grid, a next step would be to see if it can be established what the relative importance of various drivers is (including variability in the ring current, electrojetc, substorm dynamics, solar insolation of the rotating Earth, ...), but that requires information on the times and locations of the impacts that is not available to us.

The claims data available to us do not allow a direct estimate of the financial impacts on industry of the malfunctioning equipment and the business interruptions attributable to such malfunctions: we do not have access to the specific policy conditions from which each individual claim originated, so have no information on deductable amounts, whether (contingency) business interruptions were claimed or covered or were excluded from the policy, whether current value or replacement costs were covered, etc. Moreover, the full impact on society goes well beyond insured assets and business interruptions, of course, as business interruptions percolate through the complex of economic networks well outside of direct effects on the party submitting a claim. A sound assessment of the economic impact of space weather through the electrical power systems is a major challenge, but we can make a rough order-of-magnitude estimate based on existing other studies as follows.

The majority (59% in sample B) of the insurance claims studied here are explicitly attributed to "Misc.: electrical surge", which are predominantly associated with quality or continuity of electrical power in the low-voltage distribution networks to which the electrical and electronic components are coupled. Many of the other stated causes (see

Section 2.1) may well be related to that, too, but we cannot be certain given the brevity of the attributions and the way in which these particular data are collected and recorded. Knowing that in most cases the damage on which the insurance claims are based is attributable to perturbations in the low-voltage distribution systems, however, suggests that we can look to a study that attempted to quantify the economic impact of such perturbations on society.

That study, performed for the Consortium for Electric Infrastructure to Support a Digital Society" (CEIDS) [*Lineweber and McNulty*, 2001], focused on the three sectors in the US economy that are particularly influenced by electric power disturbances: the digital economy (including telecommunications), the continuous process manufacturing (including metals, chemicals, and paper), and the fabrication and essential services sector (which includes transportation and water and gas utilities). These three sectors contribute approximately 40% of the US Gross Domestic Product (GDP).

Lineweber and McNulty [2001] obtained information from a sampling of 985 out of a total of about 2 million businesses in these three sectors. The surveys assessed impact by "direct costing" by combining statistics on grid disturbances and estimates of costs of outage scenarios via questionnaires completed by business officials. Information was gathered on grid disturbances of any type or duration, thus resulting in a rather complete assessment of the economic impact. The resulting numbers were corrected for any later actions to make up for lost productivity (actions with their own types of benefits or costs).

For a typical year (excluding, for example, years with scheduled rolling blackouts due to chronic shortages in electric power supply), the total annual loss to outages in the sectors studied is estimated to be $46 billion, and to power quality phenomena almost $7 billion. Extrapolating from there to the impact on all businesses in the US from all electric power disturbances results in impacts ranging from $119 billion/year to $188 billion/year (for about year-2000 economic conditions).

Combining the findings of that impact quantification of all problems associated with electrical power with our present study on insurance claims suggests that, for an average year, the economic impact of power-quality variations related to elevated geomagnetic activity may be a few percent of the total impact, or several billion dollars annually. That very rough estimate obviously needs a rigorous follow-up assessment, but its magnitude suggests that such a detailed, multi-disciplinary study is well worth doing.

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Generator Thermal Stress during a Geomagnetic Disturbance

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***Abstract*— this paper investigates the operating condition of the generator during a Geomagnetic Disturbance (GMD). Generators are sensitive to harmonics and negative sequence currents, caused by the half-cycle saturation of the generator step-up transformer due to Geomagnetically Induced Current. Such harmonic currents can cause rotor heating, alarming, and the loss of generation.**

Based on the time-domain simulation in the EMTP, this study investigates the order and magnitude of the harmonics which impact the generator, and determines the rotor heating level due to such harmonics, at various levels of the GIC. The study reveals that the generator can reach its thermal capability limit at moderate GIC levels. However, the existing standards, e.g., IEEE Standards C50.12 and C50.13, fail to account for such operating conditions, and the corresponding recommendations underestimate the rotor heating level. As such, the negative sequence relays may not accurately operate under GMDs. A modification to the standards is also required which is proposed in this study.

***Index Terms*-- Generator, Power Transformer, Geomagnetically Induced Current, Negative Sequence Relay.**

I. INTRODUCTION

Geomagnetic disturbance or Solar Magnetic Storm refers to the phenomena caused by the solar flare and coronal mass ejection activities. Due to explosion on the sun surface, a large amount of the charged particles, which is also known as the solar wind, is released to the space. If the solar wind strikes the earth, it distorts the dc magnetic field of the earth and a slowly varying voltage is induced in the earth and on the power transmission lines. The induced dc voltage is discharged to ground through the grounded neutral of the power transformers and generates a quasi-dc current which is referred to as Geomagnetically Induced Current (GIC). The GIC biases the transformer core in one direction, and causes a half-cycle saturation. The saturation of transformers in turn increases the reactive power demand which endangers the power system stability. Furthermore, the unidirectional saturation of transformers creates harmonics which can cause several adverse consequences in the power system [1]-[3]. The Hydro-Quebec power system blackout and the failure of a Generator Step-Up (GSU) transformer in Salem nuclear plant, New Jersey, on March 13, 1989 are examples of the consequences of a GMD event [4]-[6].

The operation condition of generators is also influenced by the GIC. During a GMD, the increase of the reactive power demand due to the saturation of the system transformers should be compensated by the generators. As such, the generator field current increases to respond to the increase of the VAR demand. This in turn may raise another concern that the VAR generation limit of the generator can be reached, and the generator is not able to further inject reactive power to the system and regulate the system voltage.

Generators are sensitive to harmonics and the fundamental frequency negative sequence current. The negative sequence current due to the voltage imbalance induces a twice frequency in the rotor, and causes rotor heating [7]. Similarly, the current harmonics induce eddy current in the rotor surface, and produce additional power loss and excessive rotor heating [7]. Another undesired impact of harmonics and negative sequence currents is the generation of the oscillatory torque and vibration of the generator. As such, the mechanical parts of the generator are subjected to mechanical stress and the risk of damage. During the past GMD events, several abnormal conditions associated with the generators have been reported [3]. However, a quantitative investigation of the magnitude of the generator negative sequence current and the current harmonics under a geomagnetic disturbance has not been carried out.

In this paper, the magnitude and the order of the harmonics generated by the saturated transformer due to GIC are determined. Based on the time-domain simulation of a generation unit including the generator, the connected 500kV GSU transformer, and the transmission line, the harmonics and the negative sequence current impressed on the generator are obtained. This study reveals that the generator can reach its

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thermal capability limit at moderate GIC levels and the available standards do not address this issue.

II. Saturation of GSU Transformer due to GIC

When the GSU transformer is subjected to GIC, the dc current generates a dc flux offset in the core and results in a shift in the core flux, Fig. 1. The ac flux due to the system voltage is superimposed on the dc flux. If the peak of the total flux enters the saturation region of the core magnetization characteristic, the transformer is driven into a half-cycle saturation, as shown in Fig. 1. The normal transformer magnetizing current ImAC, which is small under symmetric excitation condition, increases to the unidirectional magnetizing current ImGIC, under the GIC conditions.

Fig. 2 depicts the frequency spectrum of the magnetizing current of a typical three-phase 500kV-750 MVA power transformer, when the transformer is subjected to the GIC magnitude of 100A at the neutral point of the transformer. This current corresponds to 33.3 A/phase GIC, since the geomagnetic disturbance induces the same magnitude of GIC on the three phases. Due to both unsymmetrical excitation and the core nonlinearity, the magnetizing current contains both even and odd harmonics. The frequency spectrum of Fig. 2 also reveals that the magnitudes of the harmonics are comparable with the fundamental component. Furthermore, the magnitude of the dominant harmonics gradually decreases as the order of harmonics increases. Fig. 3 shows the total harmonic distortion (THD) of the magnetizing current which exceeds 200% at the lower levels of GIC and decreases at higher GIC levels. The flow of the harmonics in the power system creates power loss, can overload the capacitor banks, increases the possibility of the resonance in the power system, and may cause mal-operation of the protective relays due to the distorted voltage and current signals.

In addition to the harmonic generation, the fundamental frequency component of the magnetizing current significantly increases with the applied GIC. Therefore, when a power system is exposed to a GMD event, the reactive power demand of the system increases. This in turn degrades the system voltage regulation and can endanger the system voltage stability. Under such conditions, maintaining the capacitor banks in service is a requirement, while they can be under stress due to the imposed harmonics. This implies that the protection settings need to be properly chosen to keep the capacitor bank in service as for as the impressed stress does not damage the capacitor.

III. System under Study and the Equipment Models

Fig. 4 illustrates the system under study. The generation unit includes a 26kV-892.4MVA turbo generator and the corresponding step-up transformer. The parameters of the generator are given in the Appendix. The GSU transformer is a transformer bank consisting of three single-phase units. The three-phase transformer is rated 525/26kV – 920 MVA, with a short circuit impedance of %14. The winding connection of the transformer is delta on the generator side and grounded wye on the high-voltage side. The generation unit is connected to the power grid through a 500kV transmission

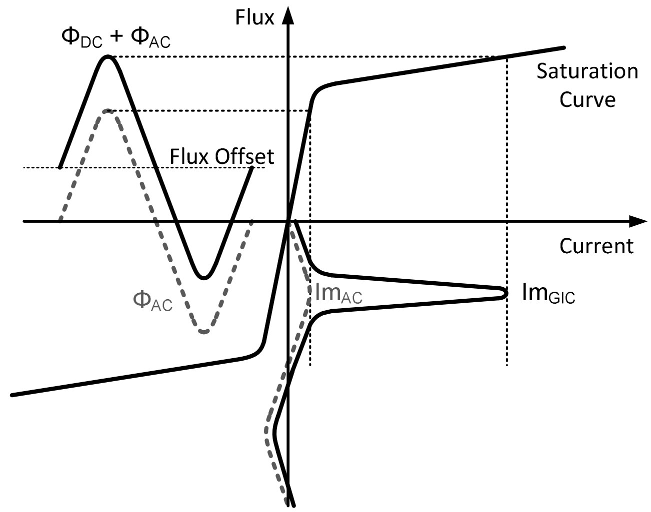

Fig. 1. Half-cycle saturation of the transformer core due to GIC

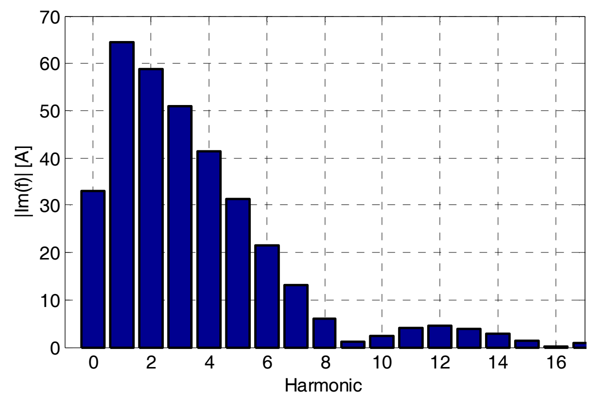

Fig. 2. Harmonics of the transformer magnetizing current at GIC=33.3 A/phase (100A at the neutral of the transformer)

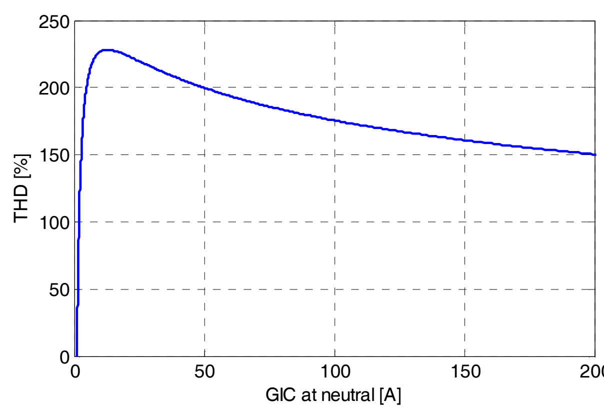

Fig. 3. Total Harmonic Distortion (THD) of the transformer magnetizing current under various GIC levels seen at the transformer neutral

line with the length of 170km and the parameters given in the Appendix. The transmission line is modeled based on a frequency-dependent representation, which takes into account the actual configuration of the conductors. The line is not transposed and therefore, represents an unbalanced voltage at the GSU transformer high voltage terminals. The 500kV power grid is represented by a thevenin equivalent with the

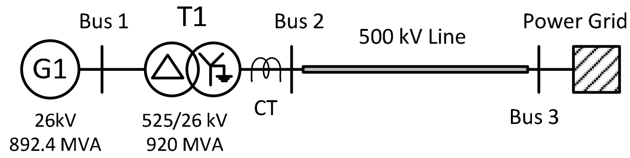

Fig. 4. System under study

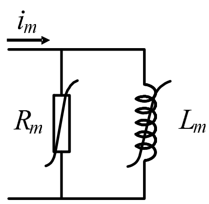

Fig. 5. Transformer core model with a dynamic core loss resistance

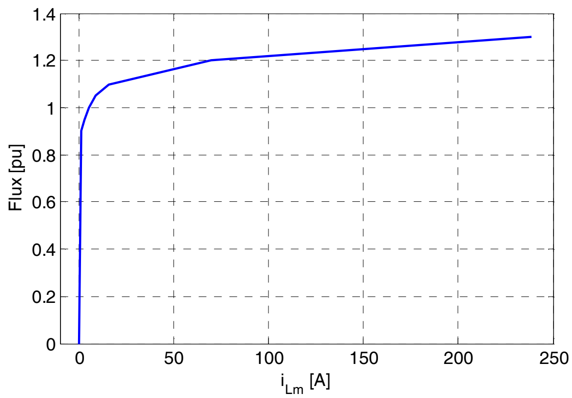

Fig. 6. Saturation curve of the GSU transformer

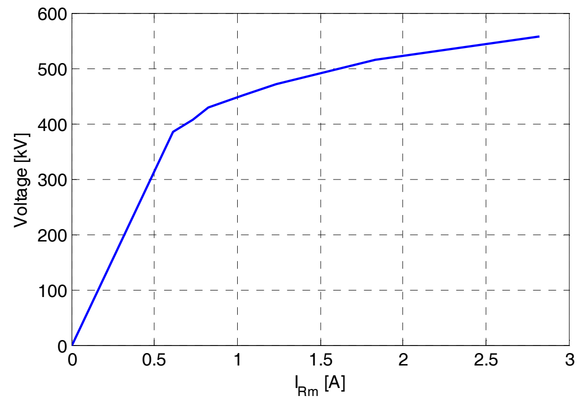

Fig. 7. Characteristic of the dynamic core loss resistance of the GSU transformer

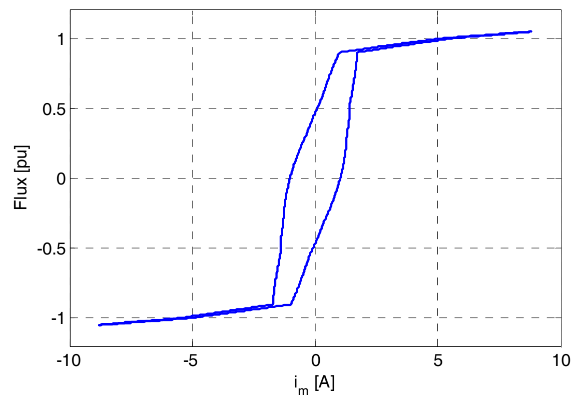

Fig. 8. Overall characteristic of the GSU transformer core at 1.1pu excitation based on the dynamic core loss model of Fig. 5 and the characteristics of Figs. 6 and 7.

equivalent impedance deduced based on the short circuit level of 50kA, at Bus 3, Fig. 4.

The main component of the system for the GIC studies is the transformer. The GSU transformer consists of three single-phase units. The transformer core is represented based on a nonlinear inductance in parallel with a nonlinear dynamic core loss resistance, Fig. 5. Figs 6 and 7 illustrate the characteristics of the nonlinear inductance and the dynamic core loss resistance, respectively. These characteristics are obtained such that the transformer no-load test current and core loss are accurately duplicated. Unlike the conventional transformer models in which the core loss resistance is constant, Fig. 7 indicates that as the excitation level increases the core loss resistance, i.e., the slope of the characteristic, decreases. Based on the characteristics of Figs. 6 and 7, Fig. 8 shows the overall characteristic of the core model of Fig. 5, which is close to an actual hysteresis core characteristic. Fig. 8 illustrates the core characteristic at the excitation level of 1.1pu.

IV. Generator Rotor Heating due to GIC

During a geomagnetic disturbance, the saturation of power transformers causes the system imbalance and generates harmonics. Such abnormal voltage and currents subject the generator to thermal and mechanical stresses. The generators are usually protected by the negative-sequence relays which operate based on an inverse-time characteristic to maintain a permissible $I^2t=constant$ thermal capability curve.

IEEE Standards C50.12 and C50.13 [9]-[10] provide recommendations for the negative-sequence capability of the salient-pole and cylindrical synchronous generators, respectively. For a turbo cylindrical generator, the permissible continuous negative sequence is deduced as

$$I_2 = 8-(MVA-350)/300, \qquad (1)$$

where I_2 is the permissible value in per-unit of the rated generator current, and MVA is the rated power of the generator in megavolt-ampere. Accordingly, the permissible continuous negative sequence for the generator under study is 6.2%.

The standards C50.12 and C50.13 also provide the guideline to take into account the impacts of the stator harmonic currents on the rotor heating. The recommendations are based on finding an equivalent negative sequence current which generates the same heat as that produced by the actual negative sequence and all the harmonics. The standards require that the equivalent negative sequence current shall not exceed the value calculated in (1). Furthermore, if 25% of the permissible current (1) is exceeded, the manufacturer shall be notified about the expected harmonics during the design or to determine whether or not the generator can withstand the harmonic heating. The equivalent negative sequence current is calculated as [9], [10],

$$I_{2eq} = \sqrt{I_2^{\ 2} + \sum_n \sqrt{\frac{n+i}{2}} I_n^{\ 2}}\ , \qquad (2)$$

where,

$i = +1$ when $n = 5, 11, 17, etc.,$

$i = -1$ when $n = 7, 13, 19, etc.$

Equation (2) is based on the fact that under continuous operating conditions, the system harmonic currents only include the odd harmonics of the fundamental frequency. In addition, the triplen harmonics appear as zero sequence currents and are eliminated by the delta winding of the GSU transformers. As such, the harmonic orders n=6k-1, k=1, 2, …, are negative sequence, and the associate air gap fluxes rotate in the opposite direction of the generator rotation. Therefore, the frequency of the induced eddy current on the rotor surface is the sum of the fundamental frequency and the harmonic frequency. On the other hand, harmonics n=6k+1, k=1, 2, …, are positive sequence harmonics and induces one order lower frequency on the rotor.

However, during a geomagnetic disturbance, both even and odd harmonics present in the generator current. Consequently, for the GIC analysis, equation (2) requires to be modified and extended to both even and odd harmonics, considering that

Negative sequence harmonics: $n = 3k-1, \quad k=1, 2,\ldots,$

Positive sequence harmonics: $n = 3k+1, \quad k=1, 2, \ldots \qquad (3)$

Since the GMD is a slowly varying event which can prolong for a few hours, the unbalanced condition and the generated harmonics caused by GIC can be considered in the context of the continuous capability of the generator. The IEEE Standard C37.102 on the protection of the AC generators [11] recommends that a relay is provided with a sensitive alarm and the negative sequence pickup range 0.03–0.20 pu to notify the operator when such a setting is exceeded.

As a case study, it is assumed that the system of Fig. 4 initially operates under normal conditions and generator G_1 delivers 800MW to the grid. Under such a condition, various levels of GIC are applied to the GSU transformer, and the generator negative sequence current and the current harmonics are calculated. The CPU time with a 2.53GHz dual-CPU computer is 4.3sec for obtaining the steady-state condition of each GIC level. Under the neutral GIC of 200A, Fig. 9 shows the simulated waveforms of the transformer magnetizing currents, and Fig. 10 depicts the harmonic components of the generator current. Due to the balanced GIC flowing in all phases, the dc current magnitude of the phase current is one third of the GIC observed at the neutral point of the GSU transformer. Fig. 10 indicates that the second harmonic is the dominant one, and the 4[th] and the 7[th] harmonics are also present in the generator current.

Table I summarizes the calculated fundamental component (I_2) and the effective negative sequence current (I_{2eq}) of the generator for various levels of the neutral GIC, in the range of 100A to 300A. Such a GIC range is considered as the moderate level of GMD. Based on the permissible negative sequence current of 6.19%, Table I reveals that at the moderate neutral GIC of 150A and higher, the effective negative sequence current exceeds the capability limit of the generator and can cause damage to the generator rotor. Even if the negative sequence relay of the generator filters the harmonics, the fundamental frequency of the negative sequence current (I2) is within the alarming range (higher than 3%) at the significantly lower GIC levels.

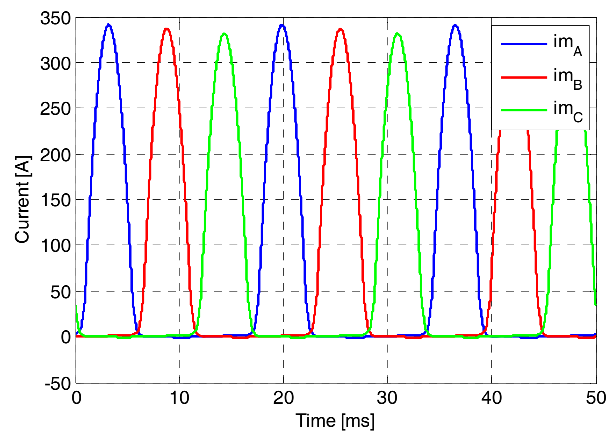

Fig. 9. Generator current harmonics under GIC of 200A at the neutral of the GSU transformer

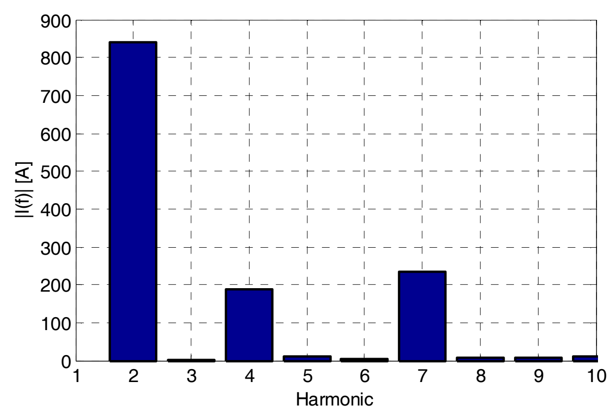

Fig. 10. Generator current harmonics under the transformer neutral GIC of 200A

TABLE I
FUNDAMENTAL FREQUENCY AND EFFECTIVE NEGATIVE SEQUENCE CURRENTS WHICH CAUSE ROTOR HEATING AT VARIOUS GIC LEVELS (PERMISSIBLE I_{2EQ}=6.19%)

GIC at neutral (A)	HV bus voltage THD (%)	I_2 (%)	I_{2eq} (%)
100	1.38	4.28	5.37
150	2.24	4.39	6.20
200	2.71	4.41	6.78
250	2.51	4.58	7.48
300	2.13	4.71	8.07

V. CONCLUSIONS

In this study, the magnitudes of the negative sequence current and the harmonic currents which impressed on the generator during a Geomagnetic Disturbance (GMD) are investigated. The harmonics are generated by the half-cycle saturation of the GSU transformer due to the GIC. Such harmonic currents cause rotor heating, can result in the mal-operation of protective relays, and the loss of generation.

Based on the time-domain simulation, this study indicates that the relevant IEEE standards C50.12 and C50.13 require modifications to take into account the even harmonics of the generator current during a GMD event. The standards underestimate the effective negative sequence current which contributes to the rotor heating. Such an effective current determines the capability limit of the generator to withstand the fundamental negative sequence and harmonic currents and is a basis for the associated relay settings. The simulation results reveal that the generator capability limit can be exceeded at moderate GIC levels, e.g. 50A/phase, and the rotor damage is likely during a severe GMD event.

VI. APPENDIX

The generator data are based on the benchmark [8] as follows,

Parameter	Value
X_d	*1.79 pu*
X'_d	*0.169 pu*
X''_d	*0.135 pu*
X_q	*1.71 pu*
X'_q	*0.228 pu*
X''_q	*0.2 pu*
T'_{do}	*4.3 s*
T''_{do}	*0.032 s*
T'_{qo}	*0.85 s*
T''_{qo}	*0.05 s*
X_l	*0.13 pu*
R_l	*0.0 pu*

The transmission line data in per unit of 100 MVA and 500 kV are as follows. Subscripts 1 and 0 stand for positive and zero sequence impedances, respectively.

Parameter	Value
R_1	*0.00189647 pu*
X_1	*0.0214564 pu*
B_1	*2.23483961 pu*
R_0	*0.022752 pu*
X_0	*0.074057 pu*
B_0	*0.952363 pu*

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[4] P. Czech, S. Chano, H. Huynh, and A. Dutil, "The Hydro-Quebec system blackout of 13 March 1989: System response to geomagnetic disturbance", *Proc. Geomagnetically Induced Currents Conference*, Nov. 8-10, 1989, Milbrae, California, EPRI Report TR-100450, 1992.

[5] J.G. Kappenman, "Geomagnetic storms and their impact on power systems", *IEEE Power Engineering Review*, pp. 5-8, May 1996.

[6] J.G. Kappenman, and V.D. Albertson, "Cycle 22: geomagnetic storm threats to power systems continue", *IEEE Power Engineering Review*, vol. 11, no. 9, pp. 3-5, 1991.

[7] W.B. Gish, W.E. Feero, and G.D. Rockefeller, "Rotor heating effects from geomagnetic induced currents", *IEEE Trans. Power Delivery*, vol. 9, no. 2, pp. 712-719, Apr. 1994.

[8] IEEE Subsynchronous Resonance Task Force, "First benchmark model for computer simulation of synchronous resonance", *IEEE Trans. Power App. Sys.*, PAS-96, no. 5, pp. 1565-1572, Sept.-Oct. 1977.

[9] *IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above*, IEEE Standard C50.12-2005, Feb. 2006.

[10] *IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above*, IEEE Standard C50.13-2005, Feb. 2006.

[11] *IEEE Guide for AC Generator Protection*, IEEE Standard C37.102-1995, Dec. 1995.

China Data Compared to Draft NERC Std

Geomagnetic Lattitude	12.7	deg	(furthest north point geomagnetic Lattituc
Alpha Latitude Scaling Factor	0.00431		extrapolatede with f
Beta Soil Factor	0.9		No value supplied so
E from NERC Formula (V/km)	0.03	V/km	NERC Std for a One
Observed E (V/km) in China	0.67	V/km	29 - 30 May 2005 Str or 0.2 nT/s) Not a Or
Ratio = Obs (2005) / NERC Field	22		This ratio is comparir a severe One Hundre

in China grid is 12.7 degrees
de)

ormula 0.001*EXP(0.115*12.7)

assumed a high value of 0.9

Hundred Year Storm (i.e. 4,800 nT/min)

om, Weak K7 Strom, dB/dt = 30 nT/min (
ne Hundred Year Storm

ng the Field for a Weak Observed Field to
ed Year NERC field

SUPPLEMENTAL COMMENT OF REP. ANDREA BOLAND

I'd like to add the following, on behalf of the people of Maine and the 182 of the 185 members of the Maine State Legislature who voted to have the Maine PUC provide a report on the best information available to advise the Maine Legislature on the vulnerabilities of the Maine electric grid and the options available for protecting it. Hearings and work sessions before the Joint Committee on Energy, Utilities and Technology, on this legislation showed the electric utilities and ISO-New England to first be in denial of any real problem from GMD, and then be startlingly unable to answer many technical and operational questions posed to them b committee members. They repeatedly referred to NERC as the authority they follow, so their weak presentation diminished the confidence we might otherwise have had in NERC's own expertise and guidance. The engineer representative from ISO-New England was particularly disappointing.

Unfortunately, the Maine PUC's work has continued to look towards the utilities and NERC standards for authoritative information, even in the face of the far more detailed examinations by nationally known experts that was presented to them, and despite Central Maine Power's own historical, real-world data that was made available to them in the committee meetings. In the last scheduled meeting of the study task force, we had two presentations. One, building off Power World modeling and real-world data, found it would be important to protect eighteen of our most important transformers with neutral ground blockers and GIC monitors to achieve a survivable level of protection. The Central Maine Power presentation found it was not necessary to do anything at all, using NERC benchmarks and suppositions; they did not use their own real-world data or give answers as to why they had not.

As a state legislator, in touch with many national experts on science and policy, I have worked at understanding the problem of poor or absent standards and their consequences for the protection of the electric grid. I have studied the potential protections available, and the very low costs for critical, tested equipment that could save the State of Maine from societal and economic collapse. The costs would be pennies per household per year for just about five years. Average legislators and lay people easily see the sense of installing such protective equipment, finding that, "If it's good enough for Idaho National Labs, it should be good enough for us." It's clearly very cheap insurance. The question we all have is, "Why is this job not getting done?" The answer seems to lie ultimately with NERC and a seemingly compromised FERC, as they seem to exert so much influence over the lives of Americans.

The states are within their rights to protect their own electric grids, and several are working to do it. They should not be subjected to lies and pretensions that can threaten to compromise their own processes. I'd like to ask, as a representative of the Maine public, that NERC either find the integrity to produce, in a timely way, the excellent work product that is expected of them, and live up to the duty entrusted to them, or get out of the way of those who are more conscientiously and expertly advising the electric utilities of the United States of America.

Respectfully submitted,

Andrea Boland

Representative Andrea Boland
Sanford, Maine

Comments of John Kappenman, Storm Analysis Consultants & Curtis Birnbach, Advanced Fusion Systems Regarding NERC Draft Standard on GIC Observations and NERC Geo-Electric Field Modelling Inaccuracies

Several comments have been provided to the NERC SDT by this commenter which the NERC SDT has failed to properly assess , interpret the data and analysis provided in these comments[1,2].

The NERC SDT claimed to have examined the Chester geo-electric field using Ottawa 5 second cadence data and concluded that the geo-electric field would be substantially larger than 1 V/km calculated using the NERC modeling methods from NRCan Ottawa 1 minute data. In the White Paper, the GIC observed at Chester and a detailed knowledge of the grid verifies that the actual geo-electric field was ~2 V/km during the May 4, 1998 storm. For reasons not explained by the NERC SDT, they failed to use the 10 second cadence magnetometer data actually measured at Chester but instead only used the high cadence data from Ottawa which was over 550kM west of Chester. This Chester data was provided in Figure 15 of the Kappenman/Radasky white paper which was submitted in July 2014 and the data and comments related to that data are provided in Figure 1 of this document.

At the time that the White Paper was submitted, NERC had not yet made publicly available their geo-electric field simulation model. Therefore it was not possible to independently test the NERC model results for the 10 second data at Chester and 1 minute data from Ottawa had to be used instead, which was publicly available. Because the NERC Model is now available, this model can now be used to calculate the geo-electric field at Chester using the Chester 10 second magnetometer data and provide an even more detailed examination of the degree of error that this model is producing versus actual observations. Figure 2 provides a comparison of the 10 sec cadence magnetometer data in the NERC model versus the previously discussed 1 minute data. As this comparison shows, the NERC model using the 10 sec data still provides only a geo-electric field peak of ~1 V/km, rather than the 2 V/km necessary to agree with actual GIC observations. As discussed in the White Paper, the NERC Model is understating the actual peak by nearly a factor of 2 at this location, a large uncertainty.

1. John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.
2. Kappenman, Birnbach , Comments Submitted to NERC on October 10, 2014

Figure 1 – Figure from Kappenman/Radasky White Paper showing locally measured 10 sec magnetometer data from Chester versus the Ottawa 1 minute data around the critical 4:39UT time span

At Chester some limited 10 second cadence magnetometer data was also observed during this storm, and Figure 15 provides a plot of the delta Bx at Ottawa (1 minute data) compared with the Chester delta Bx (10 sec) during the electrojet intensification at time 4:39UT. As this comparison illustrates that at this critical time in the storm, the disturbances at both Ottawa and Chester were nearly identical in intensity.

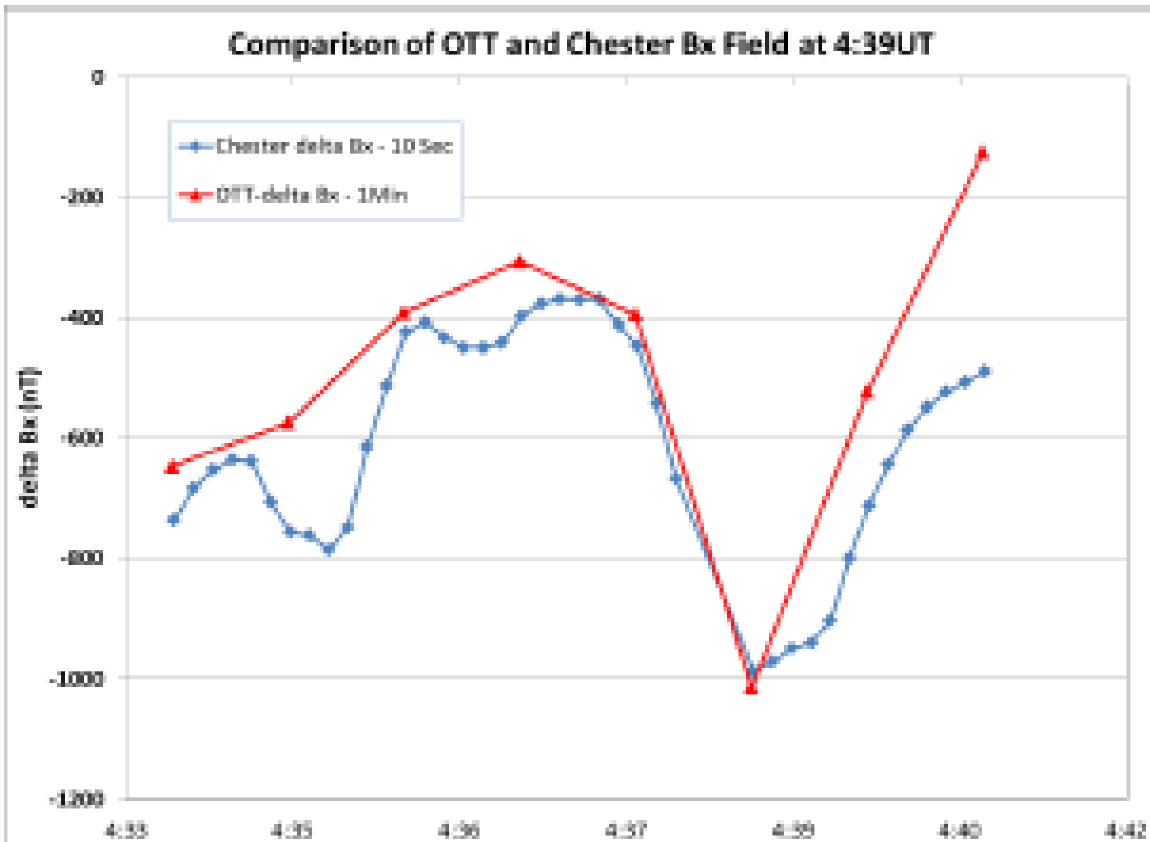
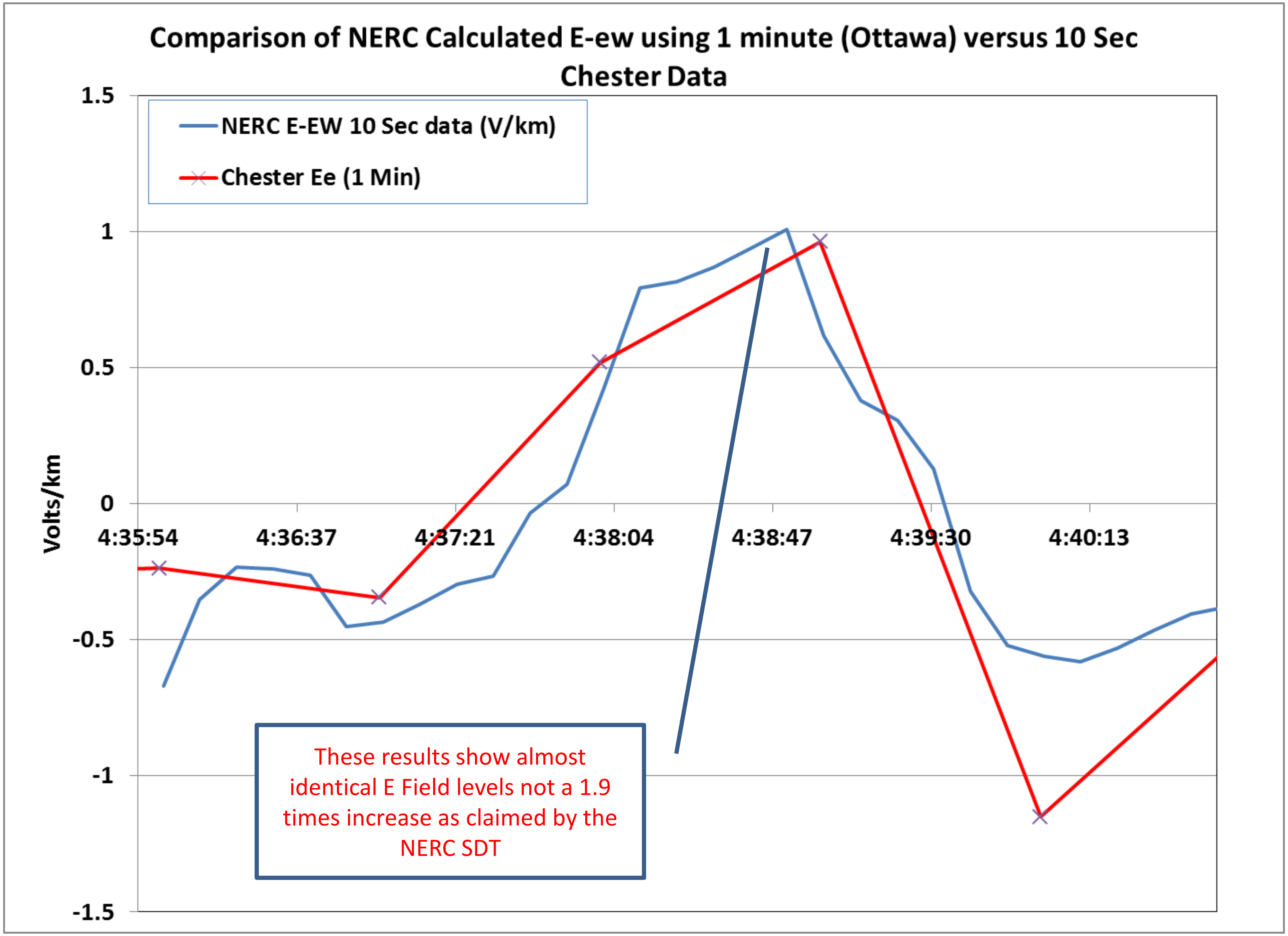


Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.

Figure 2 – Results of the NERC geo-electric field simulation model developed by Marti, et. al., with input of the 10 sec data over this study period.



The NERC SDT in their brief and inadequate response to the Kappenman/Radasky White Paper responded with the following sentence, as shown below:

> *"The method has been shown in numerous studies to accurately map the observed ground magnetic field to the geoelectric field and observed GIC (e.g., Trichtchenko et al., 2004; Viljanen et al., 2004; Viljanen et al., 2006; Pulkkinen et al., 2007; Wik et al., 2008)."*

These papers are all papers that Pulkkinen from the NERC SDT has co-authored and they also consistently confirm the same symptomatic geo-electric field simulation errors noted in the Kappenman/Radasky White Paper. In that for high dB/dt impulses, the calculated geo-electric field and resulting GIC simulations are severely understated. For example when looking at results published in the Viljanen, Pulkkinen 2004 publication noted above, the same greater than factor of 2 error shows up again in this paper as well. Figure 3 provides a model validation simulation which is Figure 8 from this paper[3]. In this figure, the intense GIC spike is highlighted in red and how the model results significantly diverge from measured GIC for these important intensifications. Figure 4 provides a plot of the observed geomagnetic field dB/dt for this same storm for an observatory close to the GIC observations and model validation provided in Figure 3. As this analysis clearly shows, at the peak dB/dt of ~500 nT/min, the Pulkkinen model diverges from reality by approximately a factor of 2 too low. This exhibits an identically similar pattern of error and low estimates as noted in Figures 31 and 32 of the Kappenman/Radasky White Paper when examining other published work of Pulkkinen. Hence the publications the NERC SDT has cited as being important to prove their model integrity, actually continue to show serious and pronounced systematic errors that have been made in their modeling approaches.

3. Fast computation of the geoelectric field using the method of elementary current systems and planar Earth models, A. Viljanen, A. Pulkkinen, O. Amm, R. Pirjola, T. Korja,*, and BEAR Working Group

Figure 3 – GIC Model validation from Viljanen, Pulkkinen paper with GIC modeling errors noted.

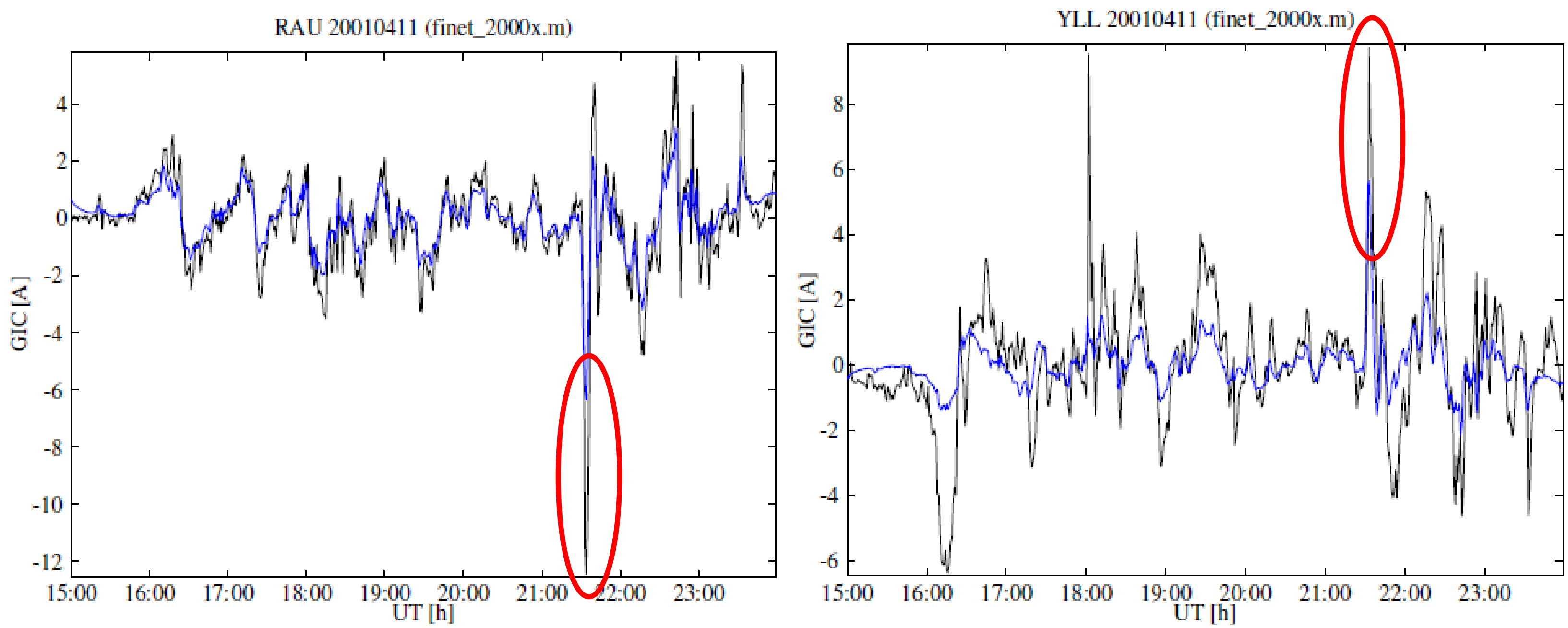
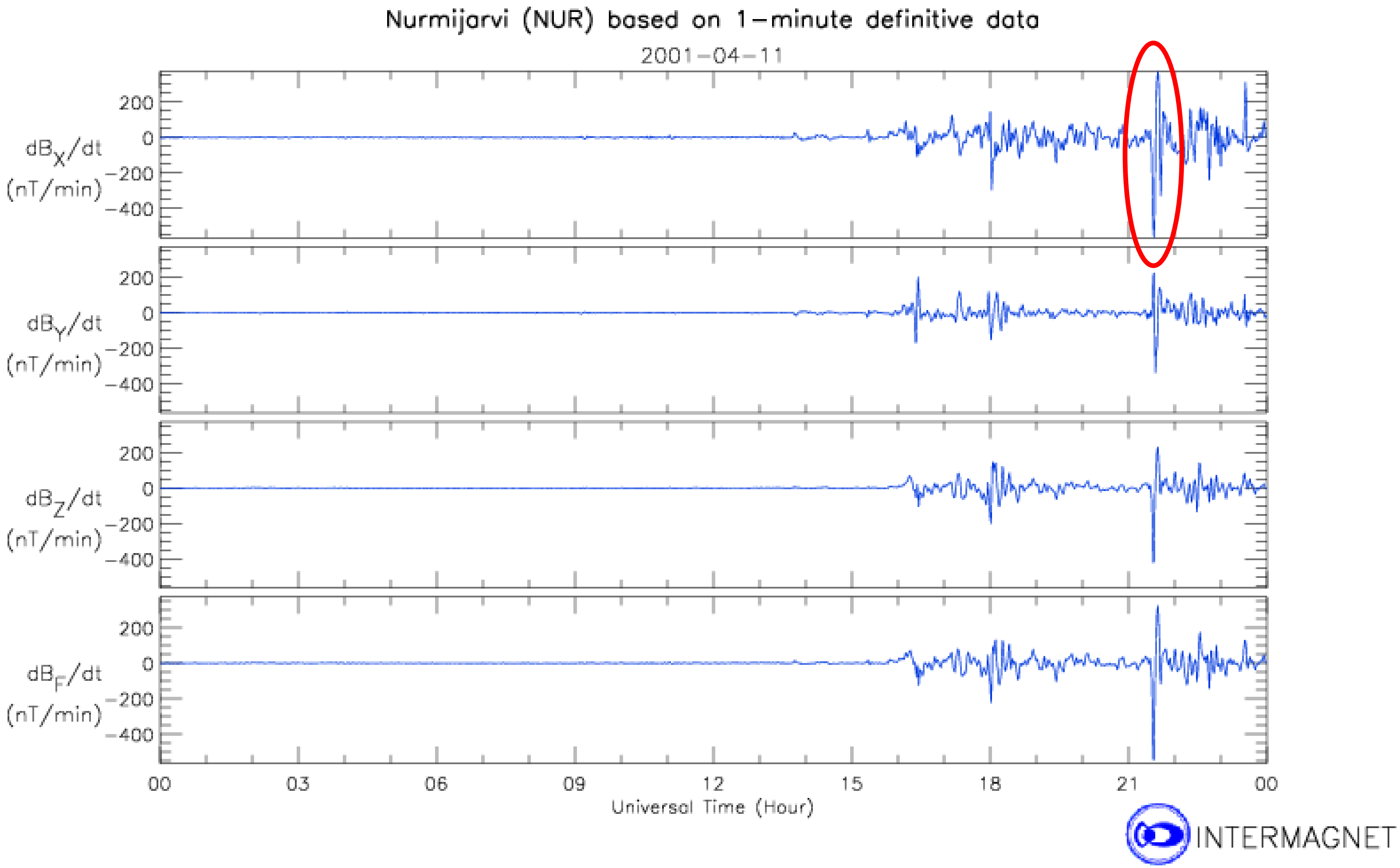


Fig. 8. Measured (black line) and modelled (blue line) geomagnetically induced currents at the Rauma (RAU) and Yllikkälä (YLL) 400 kV transformer stations on 11 April 2001.

Figure 4 – Corresponding observed dB/dt that are associated with the Viljanen, Pulkkinen paper with GIC modeling errors noted in Figure 3.



In regards to the comments provided in Oct 2014 by Kappenman/Birnbach, the NERC SDT provided this response:

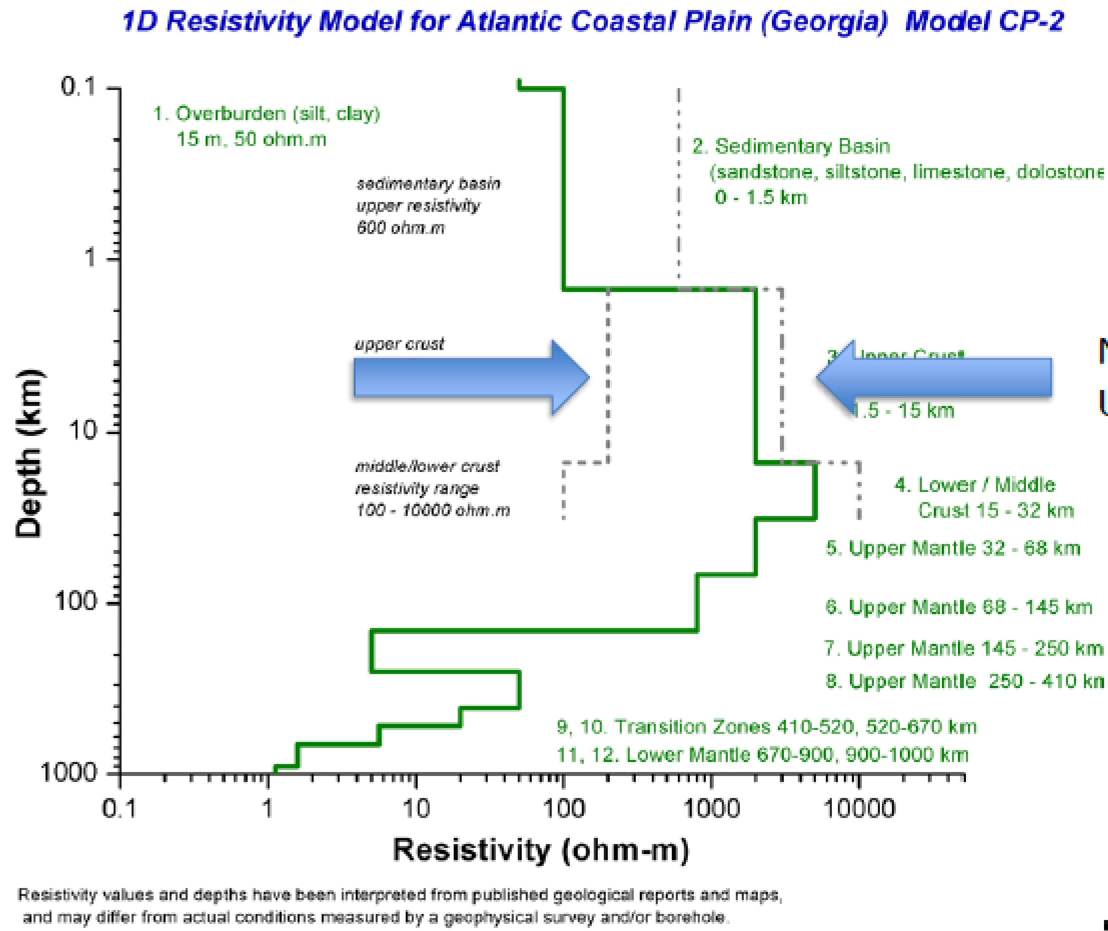
> *"The commenter's approach for using GIC data to calculate geoelectric fields is valid when an accurate power system model, ground conductivity model, specific power system configuration at the time of measurement, and high data rate magnetometer data is available. Calculations are not accurate without all elements. With limited data it is not feasible to develop a technically-justified benchmark using the commenter's approach."*

It should be noted that in the case of the Chester GIC data from May 4, 1998, the details on the transmission network are well known, there is also high cadence magnetometer data as well at the location of the GIC measurement. What had not been well confirmed is the accuracy of the ground model NERC proposed or the reliability of the geo-electric field simulation model that NERC has been using. This use of GIC data and Ohm's law to validate the ground model is a well-proven approach and it is simply not credible that the NERC SDT would raise any objection to this. Further it is fully possible just using GIC observations and knowledge of the power grid (which is precisely known) to calculate the actual driving geo-electric field even if there is some uncertainty as to the local geomagnetic field.

The NERC SDT notes that *"with limited data it is not feasible to develop a technically-justified benchmark",* but in contrast that is exactly what the NERC SDT has been doing in developing their Beta factors on un-validated ground conductivity models. In a NERC GMD Task Force meeting in Atlanta on Nov 14, 2013, Dr. Jennifer Gannon from the USGS provided a presentation on the US ground models she developed for NERC and in her presentation she pointed out the large scale uncertainty in these models. In Figure 5 is a slide from her presentation where she showed an example of the ground conductivity model uncertainty for the 1D models. In Figure 6, she provides a slide which showed a factor of 4 error range in the geo-electric field when looking at two different ground model formulations that are within the range of uncertainty. She further noted that this could only be addressed by the NERC members providing GIC observations as a way to test and validate these ground models to a lower range of uncertainty. This important validation task was never performed by NERC. Yet the NERC SDT drafted a standard which as shown in Figure 7 has determined ground conductivity model Beta factors that are defined to two significant digits after the decimal point. These Beta factors are an illusion of accuracy that the NERC SDT has put forward that is not realistic and cannot be scientifically substantiated. The only means to overcome these limitations are to begin examining the GIC observations that are available, an effort which the NERC SDT has continues to refuse to perform.

Figure 5 – Slide Presented by Jennifer Gannon USGS on Ground Conductivity Model Uncertainty on Nov 14, 2013

1D Conductivity



NOTE RANGE OF UNCERTAINTY

This is the 1-D conductivity model for an example region, CP2.

USGS
science for a changing world

Figure 6 – Slide Presented by Jennifer Gannon USGS on Geo-Electric Field Error Range due to Ground Model Uncertainty

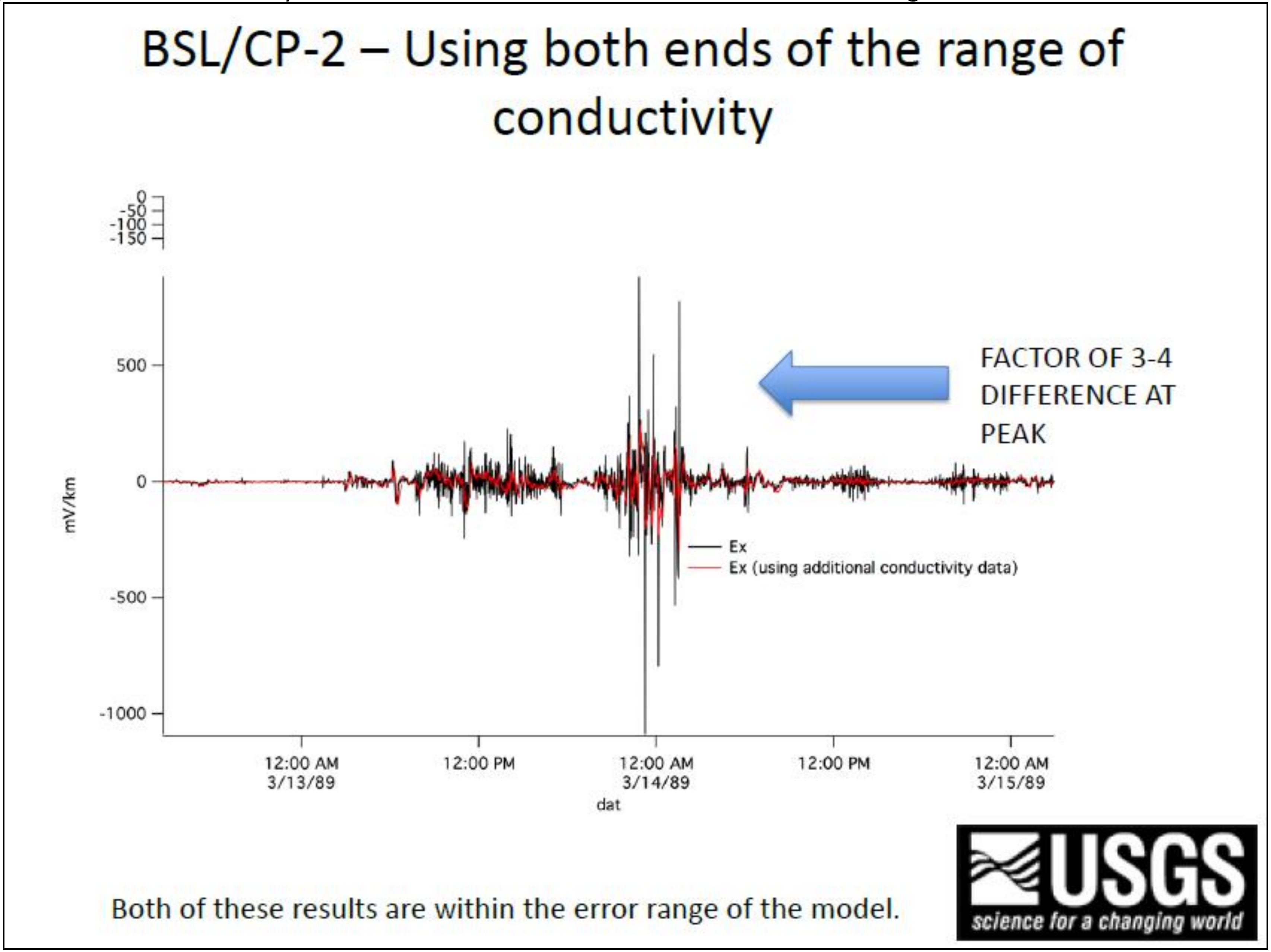


Figure 7 – NERC Draft Standard Benchmark Geo-electric field scaling factors

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Comments of John Kappenman, Storm Analysis Consultants
Regarding NERC Draft Standard on Transformer Thermal Impact Assessments

There are serious errors and omissions in the proposed revisions from the NERC GMD Standards Task Force in regard to increasing the GIC Threshold from 15 Amps/phase to 75 Amps/phase. Both Analytical analysis and actual observation data show that problem onsets could occur at much lower GIC levels.

Figure 1 is from the Recent NERC Screening Criteria publication which shows their results of screening several transformers for thermal increases due to GIC. It must be noted that these results all ignore important factors. The most important being that the Tertiary windings on the autotransformers are the most vulnerable portions of these transformers and that the testing that was performed was conducted in a manner to obscure or hide this vulnerability. He4nce it was not properly considered. In the case of the FinnGrid transformer, the Owners and Manufacturers noted that the transformer was considered to account for relatively high stray fluxes in the design stage[1,2]. Hence this transformer may have higher GIC tolerance than exists for almost all other US transformers that were not designed with GIC considerations and have been in service for many years. Further the FinnGrid transformer is a 5 Legged Core Design which is seldom used anywhere in the US electric grid. And also has higher GIC withstand than comparable single phase transformers which largely populate the 500 and 765kV grid.

Figure 2 provides a plot of NERC Table 1 from the same publication which of the Upper Bound of Peak Metallic Hot Spot Temps that are also shown in Figure 1. Figure 3 provides a revised plot which now includes the tertiary winding heating that was provided the NERC SDT in May 2014 comments[3]. These omitted winding heating curves when added provide much lower levels of GIC withstand than the proposed NERC revision of this standard.

1. M. Lahtinen, J. Elovaara: GIC occurrences and GIC test for 400 kV system transformer. IEEE Trans on Power Delivery, vol 17, no 2, April 2002, p555-561.
2. Nordman, Hasse, "GIC Test on a 400kV System Transformer", IEEE Transformer Standards Committee Meeting, GIC Tutorial, March,2010.
3. Kappenman, J.G., Section 2. – Analysis of Autotransformer Tertiary Winding Vulnerability, Comments filed with NERC, May 2014.

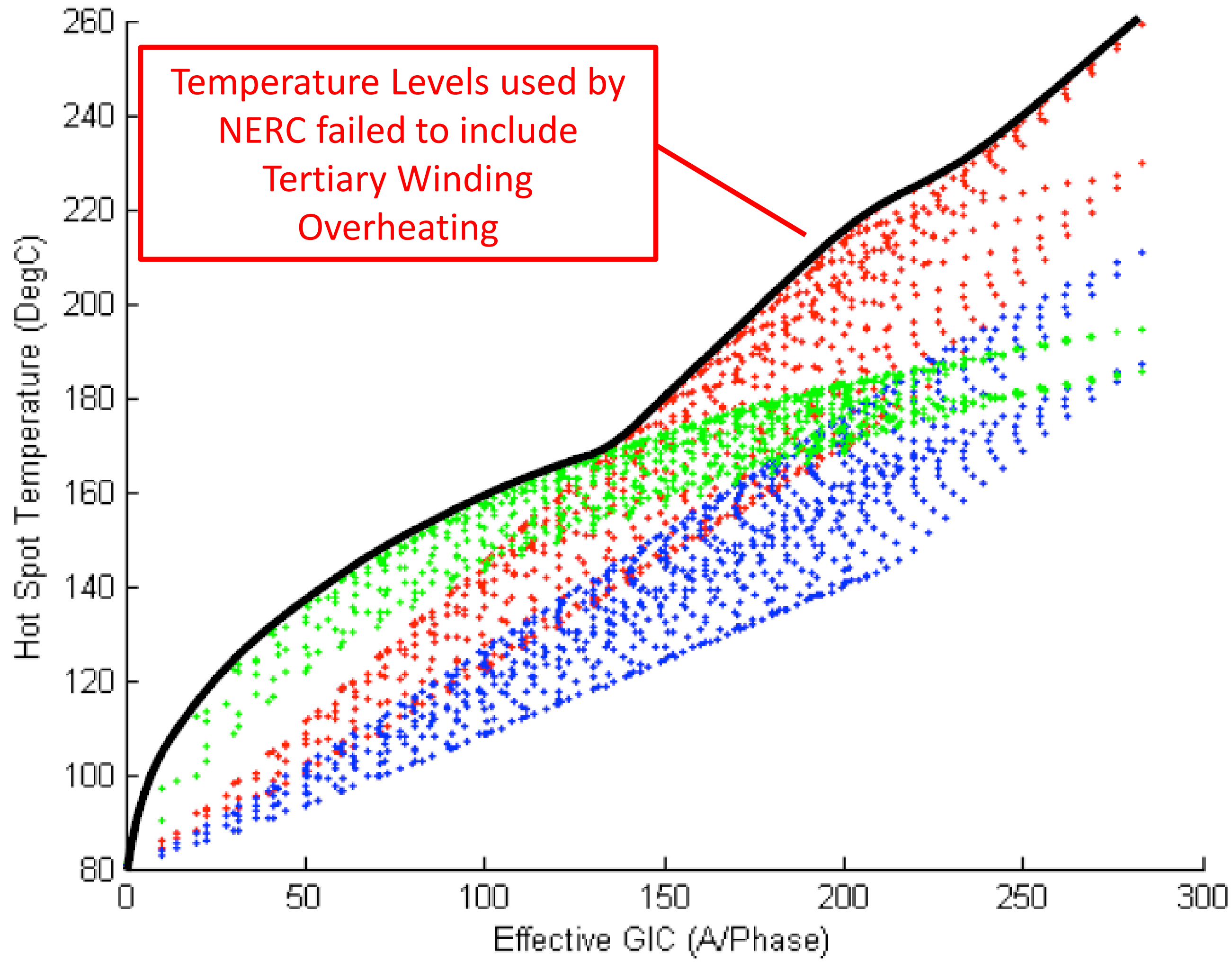


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Figure 2 – Plot of NERC Table 1 Upper Bound of Peak Metallic Hot Spot Temps

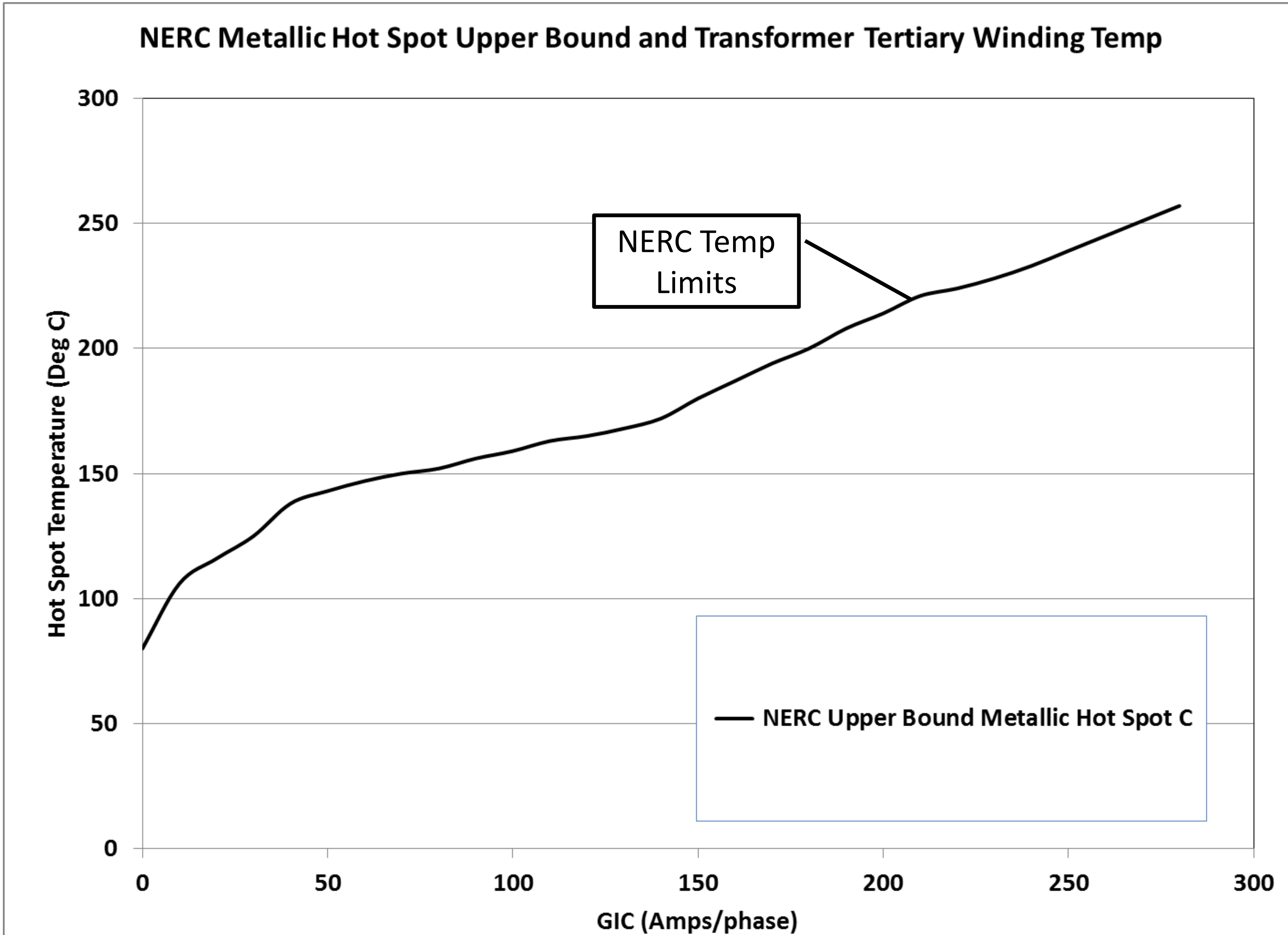
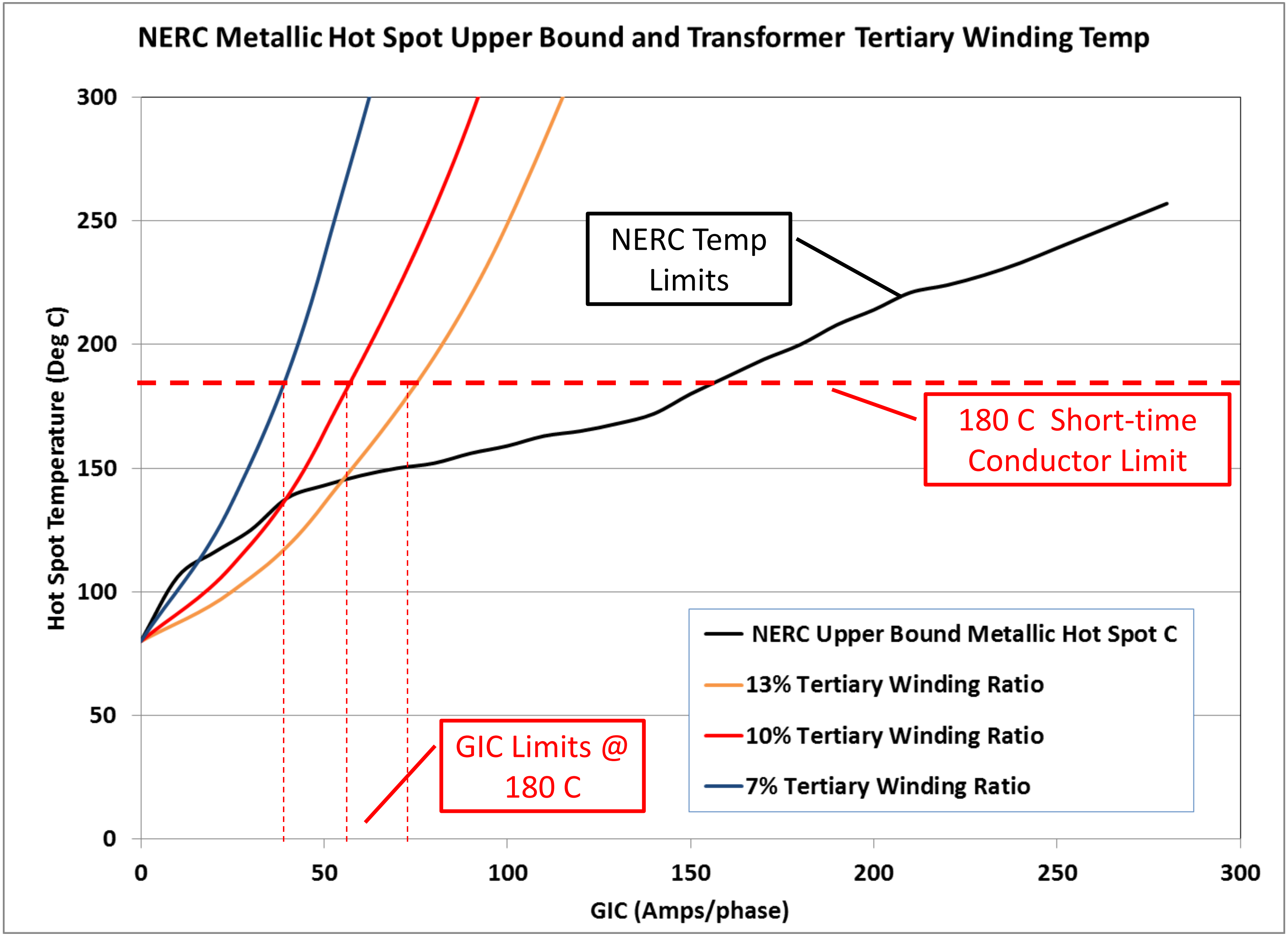


Figure 3 – Plot of NERC Table 1 & Ignored Tertiary Winding Conductor Temperatures



While much of the available monitored GIC and transformer behavior data is being concealed from independent and public review, some small amounts of details have shown heating impacts at lower GIC levels and at higher degrees of severity than the proposed NERC draft standards and screening criteria would anticipate. In reports provided by Allegheny Power, they reported heating and irreversible deleterious impacts at 8 of their 22 EHV 500kV transformers during the March 13, 1989 storm[4]. in subsequent storms where they increased monitoring on an accessible external transformer hot spot revealed by the March 1989 storm, they found significant heating issues that could be confirmed. Figure 4 is a plot of one such observation that occurred during a minor storm on May 10, 1992 at their Meadow Brook 500kV transformer which was a three phase shell form design (again not the most vulnerable transformer design). This plot clearly shows the temperature increasing to ~170 ^{o}C in a matter of just a few minutes for an observed Neutral GIC which peaks out at 60 Amps (equivalent to 20 Amps/phase). Figure 5 provides other data samples of GIC dose and Transformer Heating Response. Again, the GIC is shown in Neutral GIC Amps and needs to be divided by 3 to convert to Amps/phase. As shown, the response is consistent and can therefore also be extrapolated to higher GIC levels[5,6].

This transformer GIC-Exposure / Temperature Response can be contrasted with the Asymptotic thermal response that is included in the NERC Screening Criteria publication. Figure 5 provides a copy of the asymptotic temperature plot (Fig 6 from NERC screening publication) which is now also modified (in red) to show the temperature rise characteristics as actually observed in the Meadow Brook transformer. As this comparison clearly illustrates, the rate of heating is much more severe in the Meadowbrook transformer than what NERC is suggesting is the broad case for all transformers, especially for the large number of existing transformers that were not specifically built or designed to take into consideration any GIC-Tolerance Design Basis.

4. P.R.Gattens, R.M.Waggel, Ramsis Girgus, Robert Nevins,"Investigations of Transformer Overheating Due To Solar Magnetic Disturbances", IEEE Special Publication 90TH0291-5PWR, Effects of Solar- Geomagnetic Disturbances on Power Systems, July12,1989.
5. P. R. Gattens, Robert Langan, " Application of a Transformer Performance Analysis System", presented at Southeastern Electric Exchange, May 28, 1992.
6. Fagnan, Donald A., Phillip Gattens, "Measuring GIC in Power Systems", IEEE Special Publication 90TH0357-4-PWR, July 17, 1990.

Figure 4 – Plot of Observed GIC and Transformer Temperatures at Meadow Brook

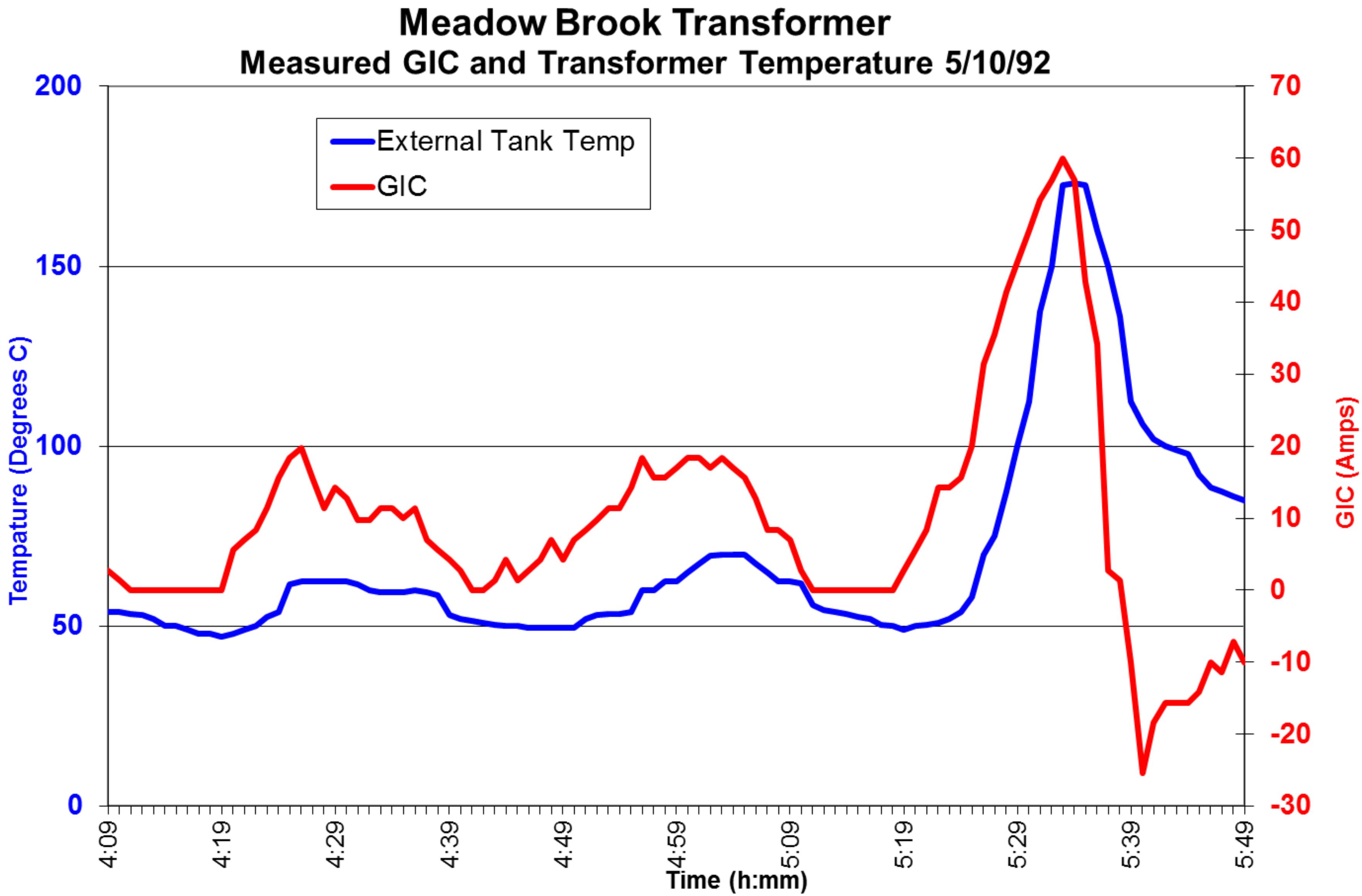


Figure 4 – Plot of Observed GIC and Transformer Temperatures at Meadow Brook

(Note to convert GIC Neutral to GIC Amps/phase, divide by 3)

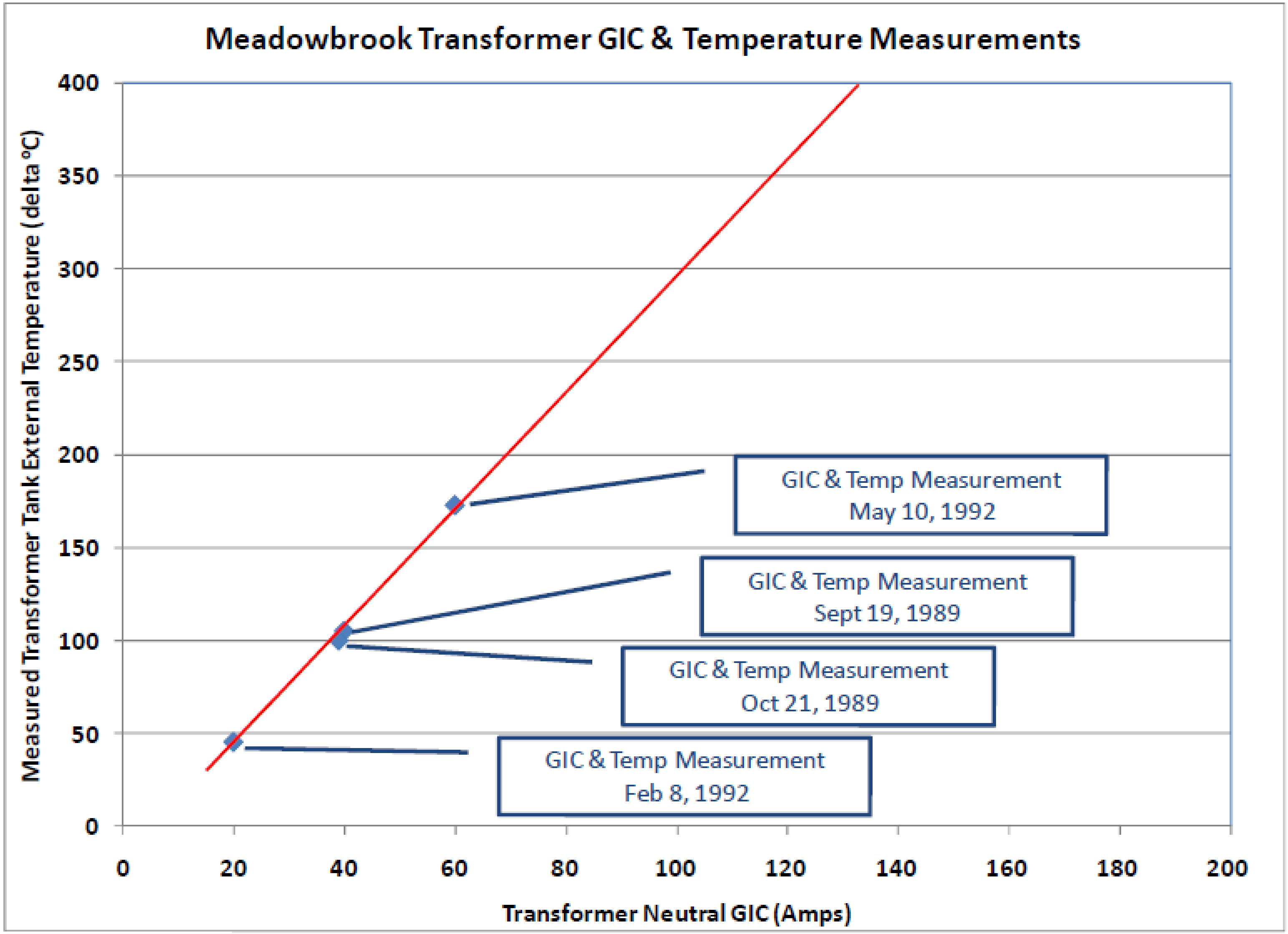


Figure 5-4 - Observation Points of GIC and Hot Spot temperatures and GIC-Temperature Trend Line.

Storm-R-112, August 2011

Figure 5 – NERC Asymptotic thermal response versus Meadow Brook actual

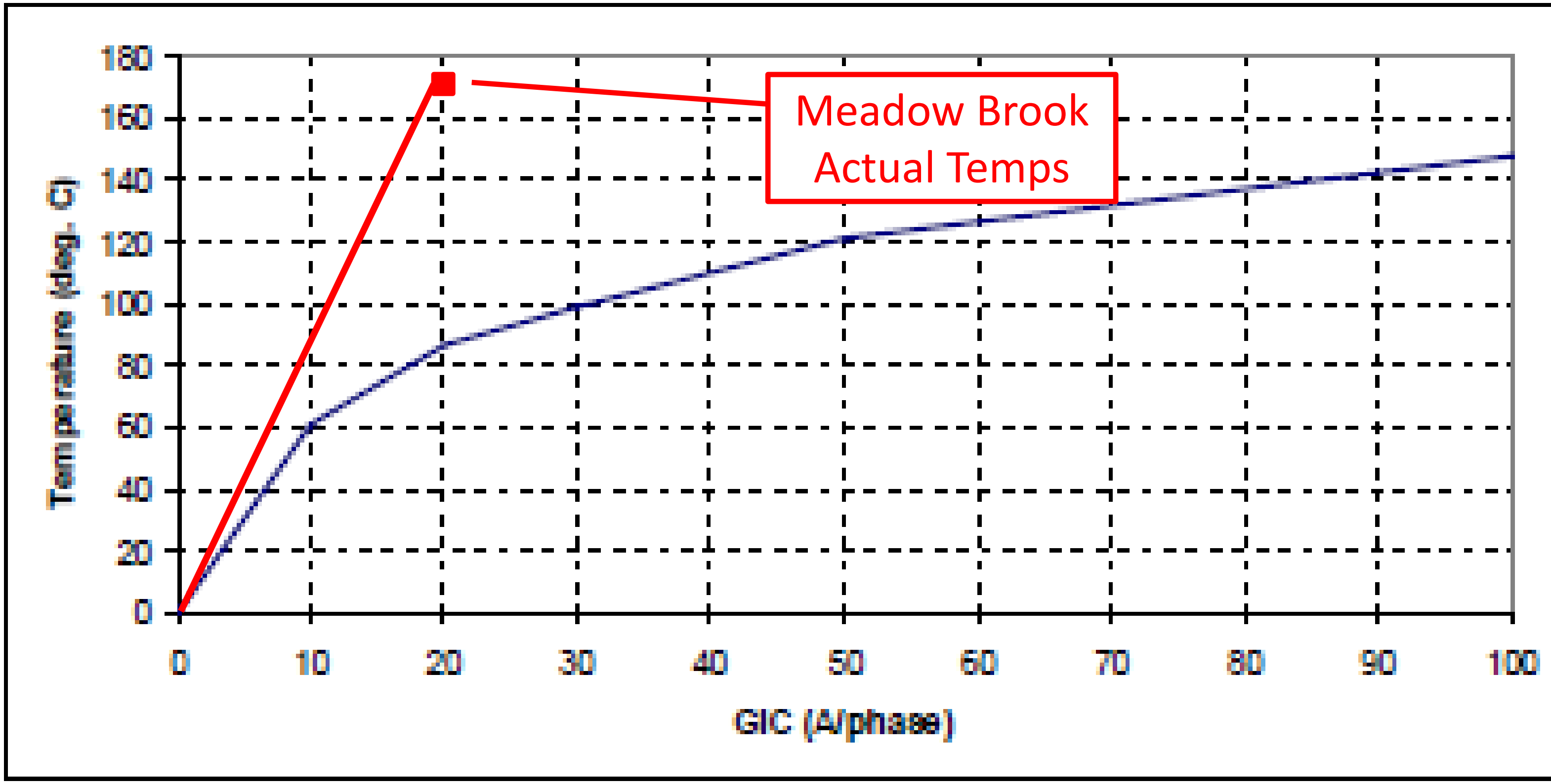


Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

To place the Meadow Brook transformer heating observations in a context that can also be applied to other existing transformers that never had a "GIC Design Basis", it is necessary to review some fundamentals in regards to GIC-caused overheating. The temperature rise experienced in any object (within the transformer and transformer tank) is affected by a number of factors, including:

- Magnitude of the Stray Flux
- Spectral content of the flux
- Magnitude and spectral content of harmonic currents in all windings of the transformer
- Orientation of the flux with respect to the major dimensions of the object
- Dimensions and mass of the object
- Material characteristics (for example permeability, conductivity)
- Heat transfer provided to the object (conduction and oil flow)

In addition to the above factors which relate only to thermal heating impacts, there are a number of other impacts that GIC could cause to a transformer which could damage and shorten its life. These include partial discharge breakdown (something that has been observed, but EPRI and industry have withheld available monitoring data) and also vibrational/mechanical failures to the transformer caused by GIC exposures.

A Brief Overview of Possible Oil Flow Constraints

In these cases and without sufficient oil flow, the temperature rise is capable of approaching ~400^{o}C or higher in a very brief period of time. While the Tank heating at Meadow Brook was associated with a spacer wood slab, the gas in oil analysis also indicated that "acetylene was probably generated by discharges not directly associated with the tank heating"[4]. Oil cooling constraints can arise from other sources, such as cooling triggered via top-oil or simulated hot-spot indicators which will not observe rapid hot-spot developments in unanticipated and very small locations in the transformer due to GIC-caused heating. Electrical Discharging also suggests processes that may still be poorly understood for GIC-exposure concerns.

GIC-caused over excitation of a transformer is an unusual mode of operation and present cooling controls on transformers are not reliably optimized to ensure proper cooling functions within the transformer when a sudden GIC exposure condition develops. For example the turn-on of oil pumps for cooling in many existing transformers is driven by a “simulated hot-spot” not actual hot-spot. The actual hot-spot can be quite different from normal loading when caused by GIC.

In the case of the Meadow Brook transformer a physical obstruction was the cause of oil flow constriction. But for all other exposed transformers, intense hot-spots can develop due to constraints on cooling system limitations as noted here. Therefore these types of existing control systems on transformers cannot be relied upon to ensure adequate oil flow and cooling conditions within the transformer and prevent the rapid transient development of intense hot-spots due to GIC exposures.

A Brief Overview of Tertiary Winding Conductor Heating

The examination of winding heating by the manufacturers and NERC has been limited to only consideration of transformer main windings which have full MVA rating and are much more physically massive than the much reduced MVA Tertiary windings of autotransformers which are also exposed to harmonics generated by the GIC flow in the transformer. Triplen harmonics will naturally circulate in these windings and at low levels of GIC can reach harmonic current levels which greatly exceed their rating leading to enormous losses and heating that is narrowly confined to this very small area within the transformer. Because of the small mass and area involved, it would be reasonable to expect higher temperature rises than noted in the NERC asymptotic charts that have been previously discussed. Further is it unclear whether a lightly load autotransformer which is experiencing a small tertiary winding heating problem would have sufficient oil flow to ensure safety of the winding.

Conclusions

The previous discussions only examined two of the large number of factors that could lead to deleterious impacts to large power transformers exposed to GIC. What has been illustrated in this discussion is the lack of a comprehensive understanding by both the NERC SDT and transformer manufacturers. This has also been coupled with efforts to withhold data and observations taken by the industry and EPRI specifically monitoring transformer impacts during geomagnetic storms. Hence the NERC efforts to increase the GIC safety threshold is being implemented without an adequate examination of all of the possible concerns.

SMARTSENSECOM, INC. COMMENTS ON PROPOSED STANDARD TPL-007-1

In recognition of the potentially severe, wide-spread impact of GMDs on the reliable operation of the Bulk-Power System, FERC directed NERC in Order No. 779 to develop and submit for approval proposed Reliability Standards that address the impact of GMDs on the reliable operation of the Bulk-Power System. In this, the second stage of that standards-setting effort, the Commission directed NERC to create standards that provide comprehensive protections to the Bulk-Power System by requiring applicable entities to protect their facilities against a benchmark GMD event.

In particular, FERC directed NERC to require owners and operators to develop and implement a plan to protect the reliability of the Bulk-Power System, with strategies for protecting against the potential impact of a GMD based on the age, condition, technical specifications, or location of specific equipment, and include means such as automatic current blocking or the isolation of equipment that is not cost effective to retrofit. Moreover, FERC identified certain issues that it expected NERC to consider and explain how the standards addressed those issues. *See* Order No. 779 at ¶ 4. Among the issues identified by FERC was Order No. 779's finding that GMDs can cause "half-cycle saturation" of high-voltage Bulk-Power System transformers, which can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. FERC also found that half-cycle saturation from GICs may severely damage Bulk-Power System transformers. While the proposed standard addresses and explains transformer heating and damage with a model, NERC ignores the issues of harmonic generation and reactive power consumption caused by a GMD event that have caused grid collapse in the past.

FERC has also been very clear to NERC that it considered the "collection, dissemination, and use of GIC monitoring data" to be a critical component of these Second Stage GMD Reliability Standards "because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models." *See* Order No. 797-A, 149 FERC ¶ 61,027 at ¶ 27. However, the proposed standard fails to tie the actions required under the standard to any actual grid conditions. In its place, the proposed standard relies entirely upon an untested system model with several suspect inputs and with no means for model verification and no affirmative requirement for real-time monitoring data as a means to enable GMD mitigation.

It has been nearly eighteen months since Order No. 779 and this comment cycle represents NERC's last opportunity to correct its course before it files TPL-007-1 with FERC. Based on the considerable volume of scientific evidence and the capabilities of modern measurement and control technology to serve as a mitigation method, the proposed standard is technically unsound and fails to adequately address FERC's directives. Rather than risk the operation of the grid on the perfection of an untested model, NERC should have provided requirements for the collection and dissemination of GMD information, such as data collected from real-time current and harmonic monitoring equipment, to ensure that the Bulk-Power System is able to ride-through system disturbances. NERC should include these measures in TPL-007-1 or be prepared for a likely FERC remand – leaving the Bulk-Power System exposed to the risk of GMD while NERC addresses the matters that it ought to have considered at this stage of the process.

1. TPL-007-1 Should be Modified to Account for the Impact of System Harmonics and VAR Consumption and Mitigate the Risk Created by Reliance On Untested System Models

In Order No. 779, FERC found that GMDs cause half-cycle saturation of Bulk-Power System transformers, which can lead to transformer damage, increased consumption of reactive power, and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. Whereas TPL-007-1 takes pains to model transformer thermal heating effects, the proposed standard does not adequately address the risks posed by harmonic injection and VAR consumption. Failure to deal directly with the effects of harmonics and VAR consumption is irresponsible given the empirical evidence of their impact upon system reliability during GMD events. Real-time monitoring, as called for by FERC, would provide the real-time operating information necessary to account for – and mitigate – these negative system effects. Real-time monitoring information would also remedy the vulnerability created by standard's "model-only" approach to the GMD threat and provide a means to iteratively improve any model over time.

A. Failure to Account for Harmonics and VAR Consumption

In the presence of a GIC, a saturated transformer becomes a reactive energy sink, acting as an unexpected inductive load on the system, and behaves more like a shunt reactor.

Consequently, transformer differential protective relays may trip and remove the transformer from service because of the disproportionately large primary current being drawn and consumed by the saturated transformer. System VAR support devices, such as capacitor banks and SVCs, become particularly critical during such conditions in order to offset the undesired behavior of GIC-affected transformers. The magnetizing current pulse of a GIC-inflicted transformer injects substantial harmonics into the power system.

VAR support devices are a low impedance path for harmonic currents and subsequently these devices begin to draw large currents too. A power flow "tug-of-war" ensues between the saturated transformers and VAR support devices. The sustenance of the VAR support devices is paramount as their failure may result in system voltage instability and collapse. However, harmonics doom these devices on multiple counts. For example, the large harmonic currents being consumed by capacitor banks may affect other components in the device that cannot withstand such high magnitude currents and result in damage and the unwanted tripping of the capacitor bank. Additionally, harmonics often result in the improper operation of protective equipment, such as overcurrent relays. Therefore, harmonics are ultimately predisposing system VAR support components to failure and increasing the vulnerability of the grid to voltage instability and collapse. See Duplessis, *The Use of Intensity Modulated Optical Sensing Technology to Identify and Measure Impacts of GIC on the Power System* (attached).

Accounting for GIC-related harmonic impacts is also essential considering that where GICs have caused significant power outages, harmonics have been identified as the primary system failure mode through the improper tripping of protection relays in known GMD events. For example, the 1989 Quebec blackout was traced to improper protective device tripping influenced by the GIC-induced where seven large static VAR compensators were improperly tripped offline by relays. See Department of Homeland Security, *Impacts of Severe Space Weather on the Electric Grid*, Section 4.4. In light of FERC's directive to address and explain how the standard address these issues, it is clear that TPL-007-1 be modified to directly account for the reactive power and harmonic effects of GMD events.

B. Over-Reliance on Untested Models

The core of the proposed standard is a series of models designed to approximate the "worst-case" scenarios of a GMD event which are, in turn, used to determine system vulnerability and whether corrective action is required. This "model-only" approach is technically insufficient and leaves the grid open to unnecessary risk. Moreover, no mechanism exists in the standards to validate the GMD models through the use of actual operating data.

First, genuine concerns exist regarding whether the "worst-case" GMD scenario is actually being modeled or whether the model substantially underrepresents the threat. For example, according to empirically-based arguments of John Kappenman and William Radasky in their White Paper submitted to the NERC earlier this year, the NERC Benchmark model under-estimates the resulting electric fields by factors of 2x to 5x. Kappenman *et al*., *Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard*. The thermal heating model also relies upon a 75 amps <u>per phase</u> assumption (equivalent to total neutral GIC of 225 amps) as the modeled parameter. As shown in the Oak Ridge Study, it was found that at as little as 90 amps (or 30 amps per phase) there is risk of permanent transformer damage. *See, e.g.,* Oak Ridge National Laboratory, FERC EMP-GIC Metatech Report 319 at 4-8 ("Oak Ridge Study"). Indeed, the Oak Ridge Study found that a 30 amps per phase level is the approximate GIC withstand threshold for the Salem nuclear plant GSU transformer and possibly for others of similar less robust design in the legacy population of U.S. EHV transformers. *See* Oak Ridge Study at Table 4-1 (finding 53% of the Nation's 345kV transformers at risk of permanent damage at a 30 amps <u>per phase</u> GIC level). In addition, the system model specified in Requirement 2 should also be run on the assumption that all VAR support components on the system (e.g., capacitor banks, SVCs, etc.) become inactive (i.e., removed from service by undesired operation of protective devices caused by the harmonics that GIC affected transformers are injecting into the system).

That the models appear to substantially under-estimate the expected GMD impact is critical as it the models alone – under the proposed standard – that drive the vulnerability assessments and corrective action plans that require owners and operators to implement appropriate strategies. As written, these models have the effect of greatly reducing the scope of the protective requirements that will be implemented, potentially allowing sizable portions of the grid to be wholly unprotected and subject to cascading blackouts despite the adoption of standards. The extensive analysis and findings of the Kappenman-Radasky White Paper and the Oak Ridge Study suggest that the modeling approach elected by NERC is technically unsound, does not accurately assess a "worst case" scenario as it purports to do, and, in any event, should not be the sole basis for the standard's applicability.

Second, the proposed standard provides no means to validate or update the standard's models in light of actual operating data. This amounts to little more than a gambler's wager that the model will adequately protect the Bulk-Power System from a substantial GMD event, when it has never actually been tested. As the model is designed, actual operating data has no means to influence or override actions based upon the model. This is inappropriate. As discussed above, it is likely that the model developed will underestimate the effects of a GMD event. To rely on a model to simulate actual equipment performance over a range of potential GMD disturbances, it is essential that that model must not only contain adequate information (i.e. – an accurate up-front estimate), but that it must also correspond to actual reported field values. NERC should modify the standard to provide that actual operating data be used to regularly verify and improve the model.

C. The Solution – Collect, Disseminate, and Use Real-Time Reactive Power and Harmonic Content Information to Mitigate GMD Impacts

While the standard's model-based approach to GMD mitigation efforts may have some limited utility as a first step towards identifying vulnerabilities and developing forward-looking correction action plans, the standard would provide far better protection with a requirement for the collection and use of accurate, real-time data regarding current, reactive power consumption, and system harmonics. Real-time data should underpin any GMD mitigation efforts, substantially reducing the risk of outages and damage to critical equipment in the event of a GMD, and would also improve the reliability of system models. Modern grid measurement and control technologies are capable and readily deployable to mitigate GMD events.

First, real-time monitoring enables protective devices to be efficiently managed during a GIC event, initiating control signals that enable devices to “ride-through” GMD where they may otherwise trip offline during a period of normal operation. In these instances, the detection of harmonic content could be used to sense transformer saturation and override normal protective device trip settings in order to maintain key equipment online and not be “fooled” into tripping by the harmonics generated by the event. Given the diversity of protective devices for equipment used throughout the Bulk-Power System, a technically preferable approach would be to actively manage protection schemes based upon real-time operating data. Regarding the system’s VAR response, if system voltage becomes unstable when VAR support is inhibited during a GIC event, operators would have an available solution through the identification of atypical harmonics, which can be associated with a GIC event, and this information used as a trigger to implement alternate protective schemes for VAR support components for the duration of the GIC event.

Second, if a GMD event is detected through the monitoring of systemic VAR consumption and harmonic content at key points in the network (which may include current monitoring on vulnerable transformer neutrals and monitoring of harmonics and VAR consumption on phases), this real-time monitoring data could be used to draw down, and ultimately cease, GMD operating procedures as the GMD event passes. Moreover, the VAR and harmonic derived from real-time operation information may also be used to trigger operating procedures, which is necessary given that the existing operational standard relies on space weather forecasts as the trigger for the implementation of operating procedures, despite the substantial error rates associated with these forecasts. Since GMD procedures impose transmission constraints that do not permit wholesale energy markets or system dispatch to achieve the most efficient use of available resources, ultimately affecting the prices paid by consumers, NERC should seek to minimize the frequency and duration of mitigation efforts. Real-time monitoring of harmonic content and reactive power would enable a more efficient approach to recognizing and reacting to GMD events, harmonizing the Phase I and Phase II standards and providing greater overall protection to the grid.

Further, real-time monitoring information must be used to validate models that are used to inform the means by which owners and operators will prepare for, and react to, GMD events. Currently, the models presented in the standard are the sole means to trigger the implementation of protection measures and the availability of actual operating data that questions the model's outputs have no means to override the model-based approach. The use of actual operating data to verify the standard's model would improve the accuracy of model verifications needed to support reliability. A better approach would be to use modeling and real-time monitoring in tandem to constantly verify and enhance the model, while still maintaining protections for "missed" events that the model is likely to inevitably overlook. The people of the United States should not have the ongoing Bulk-Power System reliability put at risk by an unverified model.

NERC should use its authority to insure that real operating data will, over time, be employed to verify and improve any reference model and that real operating data will be employed as a means to ensure ongoing system reliability when events render the reference model unequal to its protective task (which evidence suggests will happen). The proposed standard should be modified to require the collection, dissemination, and use of real-time voltage and current monitoring data which will provide the reactive power and harmonic content information necessary to effectively and efficiently manage the system in response to GMDs.

2. Conclusion

FERC was clear in its direction to NERC that the collection, dissemination, and use of real-time GIC monitoring data was a critical component of these Second Stage GMD Reliability Standards "because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models." See Order No. 797-A, 149 FERC ¶ 61,027 at ¶ 27. FERC also was clear that harmonic content and reactive power consumption created by GMD events constituted serious threats to system reliability that must be addressed. Order No. 779 at ¶ 7. The draft standard offered by NERC simply fails to meet the needs identified by FERC – which are amply supported by the record established in these proceedings – a reasonable person could reach no other conclusion.

To create a reasonable and prudent standard, NERC needs to address the reactive power and harmonic generation aspects of GMD events, and it needs to provide for verification and improvement of the model included in the draft standard. The only route to meeting those needs that is supported by the evidentiary based findings and FERC's directives is a mandate for the collection, dissemination, and use of real-time GIC current and harmonic data to drive protection schemes. With clearly articulated requirements for such data, NERC can fill the gaps in the current standard and provide a means by which to adequately protect the Bulk-Power system.

Respectfully submitted,

/s/

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The Use of Intensity Modulated Optical Sensing Technology to Identify and Measure Impacts of GIC on the Power System

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Abstract

This paper describes the phenomenon of geomagnetically induced currents ("GIC"), a geomagnetic disturbance's potential impact on transformers and the electric power system, and FERC/NERC regulation regarding utility responsibility. The paper then introduces intensity modulated optical sensing technology, explains how this technology has been adapted to measure voltage, current, phase and other characteristics of electric phenomena, and answers why this adaptable core technology provides a comprehensive solution to identifying and measuring the impacts of GIC.

Introduction

The phenomenon of geomagnetically induced currents ("GIC") has been well documented[1] and is summarized herein. Because of the catastrophic impacts a major solar storm, which precipitates GIC flow, can have on electric power grid operations and its components, the Federal Energy Regulatory Commission (FERC) issued an order in May 2013 requiring the North American Electric Reliability Corporation (NERC) to create reliability standards to address the Geomagnetic Disturbance (GMD) threat.

This paper reviews the mechanism by which the loss of reactive power occurs due to GIC and how it could lead to system voltage collapse, which is central to FERC's concerns. However, the main impetus for writing this paper is to introduce a technology that brings true system visibility within reach of utility asset managers and system operators. This visibility is paramount to the success of managing GIC effects. Practically, it is impossible to manage something you cannot measure; for example, how can you know whether the reaction is appropriate for the problem if the latter is not quantified? Increased system visibility also validates the effectiveness of strategies to block GIC.

Managing and blocking are the two mitigation approaches for dealing with GIC. Managing GIC in real time involves fast, responsive operating procedures. While modeling efforts will aid in predetermining operating steps that will help to minimize outages and limit damage to critical equipment in the presence of GIC, accurate, real-time system visibility reveals the necessity of these operating steps or need for more during each unique GMD event and guides the operator (manual or automatic) with respect to when these steps must be implemented (and when the danger is gone). Afterwards, this increased visibility will help improve the predefined thresholds of system switching and VAR support components used during GIC induced events.

Alternatively, blocking GIC can be done through several means, including the installation of a GIC neutral blocking capacitor on the neutral of a susceptible transformer, resistive grounding of the transformer

[1] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013, references.

(although this will require a higher surge arrester rating), and series capacitor blocking in transmission lines.

The technology that delivers the system visibility required to effectively manage and mitigate the threat of GMD is called Intensity Modulated ("IM") Optical Sensing. It was developed by the Naval Research Laboratory for use by the United States Navy in mission-critical applications which presented with very hostile measuring environments. IM optical sensing devices solve the measuring challenges to which other optical devices and traditional instrument transformer devices succumb, including those present during geomagnetic storms. Furthermore, the measuring capabilities of IM optical sensing devices transcend the capabilities of traditional devices. The remarkable stability of an IM optical monitoring systems in harsh measuring conditions, its higher accuracy, broadband measuring capabilities, and its real-time delivery of power system information are key to delivering a more resilient electric power grid, even and particularly in the grips of such High Impact Low Frequency events as GMD.

Geomagnetically Induced Currents

Geomagnetic storms are associated with activity on the sun's surface, namely sunspots and solar flares. Solar flares result in electromagnetic radiation (coronal mass ejections (CME), x-rays and charged particles) forming a plasma cloud or "gust of solar wind" that can reach earth in as little as eight minutes. Depending on its orientation, the magnetic field produced by the current within this plasma cloud can interact with the earth's magnetic field, causing it to fluctuate, and result in a geomagnetic storm.

Geomagnetically induced currents ("GICs") are caused when the "auroral electrojet", currents that follow high altitude circular paths around the earth's geomagnetic poles in the magnetosphere at altitudes of about 100 kilometers, becomes 'energized' and subjects portions of the earth's nonhomogeneous, conductive surface to slow, time-varying fluctuations in Earth's normally unchanging magnetic field. [1][2] By Faraday's Law of Induction, these time-varying magnetic field fluctuations induce electric fields in the earth which give rise to potential differences (ESPs – earth surface potentials) between grounding points. The distances over which a resulting electric field's effects may be felt can be quite large. The field, then, essentially behaves as an ideal voltage source between rather remote neutral ground connections of transformers in a power system, causing a GIC to flow through these transformers, connected power system lines and neutral ground points.

A power system's susceptibility to geomagnetic storms varies and is dependent upon several contributing elements, including:

- The characteristics of the transformers on the system, which serve as the entry (and exit points) for GIC flow, such as:
    - Transformer winding construction: Any transformer with a grounded-wye connection is susceptible to having quasi-DC current flow through its windings; an autotransformer (whereby the high- and low-voltage windings are common, or shared) permits GIC to

[2] John G. Kappenman, 'Geomagnetic Disturbances and Impacts upon Power System Operation,' The Electric Power Engineering Handbook, Chapter 4.9, 4-151., 2001.

pass through to the high-voltage power lines, while a delta-wye transformer does not [Figure 1].

 - Transformer core construction: The core design determines the magnetic reluctance of the DC flux path which influences the magnitude of the DC flux shift that will occur in the core. A 3-phase, 3-legged core form transformer, with an order of magnitude higher reluctance to the DC Amp-turns in the 'core – tank' magnetic circuit than other core types, is least vulnerable to GIC. Most problems are associated with single phase core or shell form units, 3-phase shell form designs or 3-phase, 5-legged core form designs.[3]
 - Transformer ground construction: Transformers on extra high voltage (EHV) transmission systems are more vulnerable than others because those systems are very solidly grounded, creating a low-resistive, desirable path for the flow of GIC. Incidentally, many EHV transformers are not 3-phase, 3-legged core form designs.

- The geographical location, specifically the magnetic latitude, of the power system: The closer the power segment is to the earth's magnetic poles generally means the nearer it is to the auroral electrojet currents, and consequently, the greater the effect.[4] Note, however, that the lines of magnetic latitude do not map exactly with geographic latitude as the north and south magnetic poles are offset from Earth's spin axis poles. Therefore, the East coast geographic mid-latitude is more vulnerable than the West coast geographic mid-latitude as the former is closer to the magnetic pole.[4]
- Earth ground conductivity: Power systems in areas of low conductivity, such as regions of igneous rock geology (common in NE and Canada), are the most vulnerable to the effects of intense geomagnetic activity because: (1) any geomagnetic disturbance will cause a larger gradient in the earth surface potential it induces in the ground (for example, 6 V/km or larger versus 1 – 2 V/km)[5] and (2) the relatively high resistance of igneous rock encourages more current to flow in alternative conductors such as power transmission lines situated above these geological formations (current will utilize any path available to it but favors the least resistive).[5] Earth's conductivity varies by as much as five orders of magnitude.[5] [Reference Figure 2.]
- Orientation of the power system lines (E-W versus N-S): The orientation of the power lines affects the induced currents. The gradients of earth surface potential are normally, though not always, greater in the east-west direction than in the north-south direction.[6]
- The length and connectivity of the power system lines: The longer the transmission lines the greater the vulnerability. Systems dependent upon remote generation sources linked by long transmission lines to deliver energy to load centers are particularly vulnerable. This is characteristic of Hydro Quebec's system in Quebec where much of its power is produced far from where it is consumed; for example, its James Bay generators are 1,000 km away from any

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[3] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.
[4] James A. Marusek, "Solar Storm Threat Analysis", Impact 2007, Bloomfield, Indiana
[5] John G. Kappenman, 'Geomagnetic Disturbances and Impacts upon Power System Operation,' The Electric Power Engineering Handbook, Chapter 4.9, 4-151., 2001.
[6] P.R. Barnes, D.T. Rizy, and B.W. McConnell, "Electric Utility Experience with Geomagnetic Disturbances," Oak Ridge National Lab, Nov. 25, 1991.

populated load center.[7] Since the GMD event that ravished their system in March 1989, Hydro Quebec has installed series capacitors on transmission lines which will block GIC flow.

- The strength of the geomagnetic storm: A more powerful solar storm increases the intensity of the auroral electrojet currents and can move these currents towards the earth's equator.

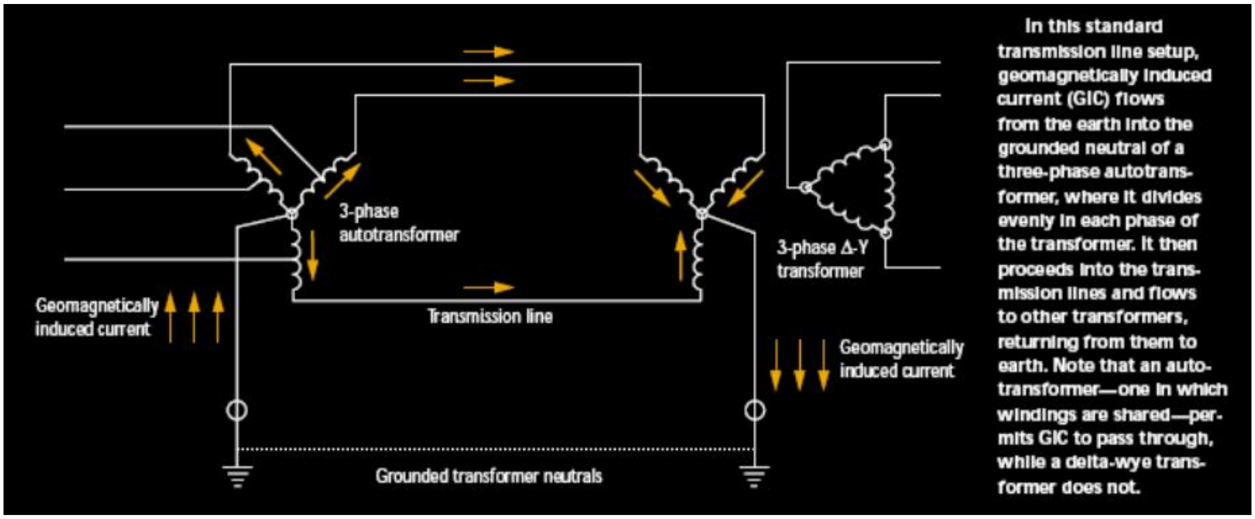

FIGURE 1
Conducting Path for GICs[8]

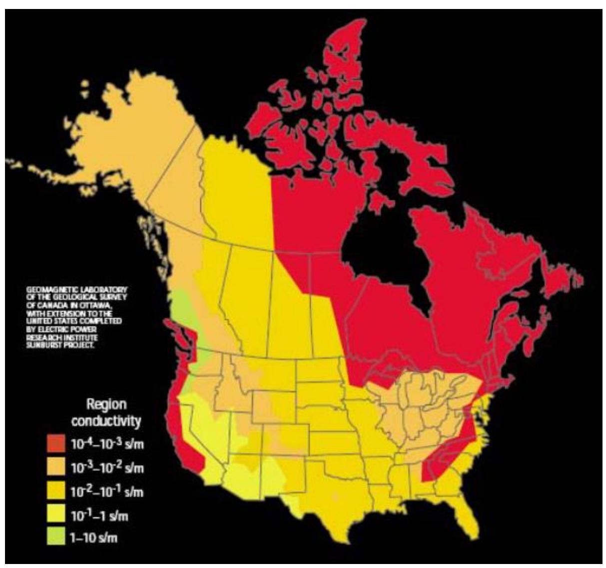

FIGURE 2
Earth Conductivity in US & Canada[8]

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[7] M. Corey Goldman, "How one power grid kept lights on", Toronto Star, September 8, 2003, http://www.ontariotenants.ca/electricity/articles/2003/ts-03i08.phtml

[8] Tom S. Molinski, William E. Feero, and Ben L. Damsky, "Shielding Grids from Solar Storms", *IEEE Spectrum*, November 2000, pp. 55-60.

The impact of GIC on afflicted transformers and corresponding electric power systems is generally understood but the many variables that influence vulnerability and therefore the inconsistency in the resultant singular manifestations of GIC lends to a near impossible cumulative quantification of a geomagnetic storm's impact on power systems. Most impact quantifications up to now have been anecdotal.

Potential Impact of GIC on Transformers and Electric Power Systems

The source of nearly all of the operating and equipment problems attributed to a geomagnetic disturbance is the reaction of susceptible transformers in the presence of GIC. Therefore, the first order effects of GIC are those on the transformer and the second order effects of GIC are those on the power system.

First Order Effects of GIC

The exciting current of a transformer represents the continuous energy required to force "transformer action", in other words, make the transformer behave as a transformer. It is largely a reactive current (usually dominated by an inductive contribution known as the magnetizing current) and typically very small as transformers are very efficient devices, usually less than 1% of the transformer's rated operating current. Under normal, steady state conditions, the exciting current of a transformer is symmetrical (balanced between the positive and negative peaks of its waveform) as shown in Figure 3; the exciting current is shown in blue on the bottom vertical axis.

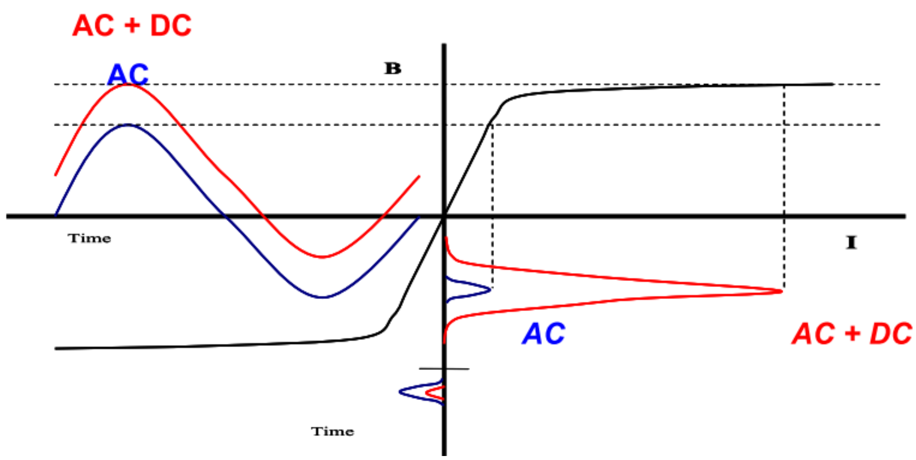

FIGURE 3
Part Cycle, Semi Saturation of Transformer Cores[9]

For economic motivations, the peak ac flux in the power transformer (given by the blue waveform on the left side of Figure 3) is designed to be close to the knee (or magnetic saturation point) of the magnetization curve (shown by the black curve in Figure 3) so that nearly the full magnetic capabilities of the transformer's core is used during operation. When a core operates below its saturation point, practically all of the magnetic flux created by the exciting current is contained in the core. The magnetic reluctance of the core is low because the core steel is an excellent conduit for magnetic flux.

[9] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.

Accordingly, the magnetization losses are low (i.e., a small I_h in Figure 4) and the (shunt) magnetizing inductance is high, resulting in a very small magnetizing current, I_m. The exciting current is the vector sum of these current contributions, I_h and I_m. The inductive volt-amperes-reactive (VAR) requirements of the transformer are very low. Moreover, with non-saturated core magnetization, the transformer voltage and current waveforms contain very low harmonic content.

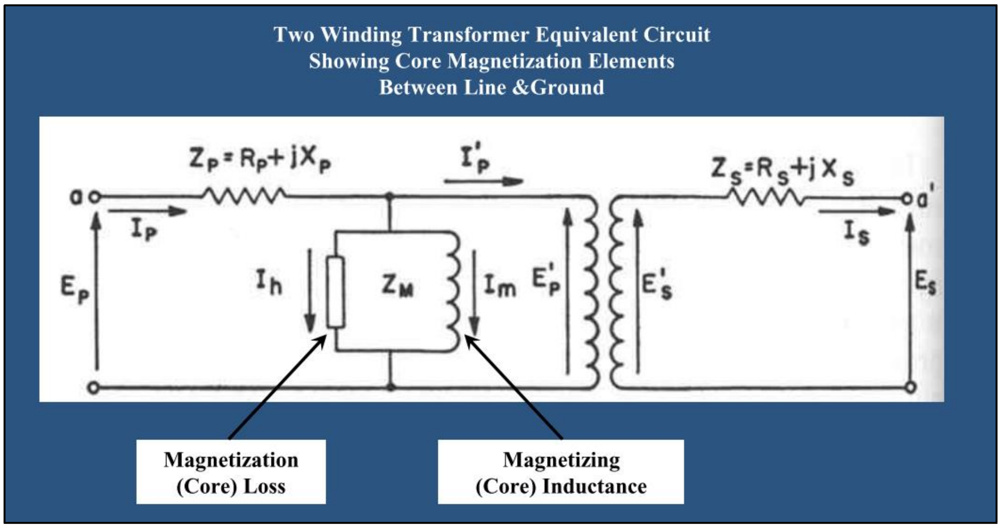

FIGURE 4
Transformer Equivalent Circuit[10]

During a GIC event, a quasi-dc current enters the ground connected neutral of the transformer and splits equally between phase windings (on multiple phase winding transformers). If the zero sequence reluctance of the transformer is low, the GIC biases the operating point on the magnetization curve to one side (see the top black dashed line in Figure 3). This bias causes the transformer to enter the saturation region in the half cycle in which the ac causes a flux in the same direction as the bias. This effect is known as half-cycle saturation.[11] When the core saturates, it has reached the limit of its ability to carry a magnetic field and any field beyond the limit “leaks” out of the core and passes through the space around the core (air/oil) as “leakage flux”. While the magnetic reluctance of the core is still low, the reluctance of the portion of the magnetic circuit outside the core is high. This results in a much-lowered value of shunt inductance and a large shunt current (I_m) flows through the magnetizing branch. The inductive volt-amperes-reactive (VAR) requirements of the transformer can become very high (see the red exciting current pulse given a DC offset on the bottom vertical axis in Figure 3). With saturated core magnetization, the transformer voltage and current waveforms contain very high harmonic content.

[10] W. Hagman, “Space Weather in Solar Cycle 24: Is the Power Grid at Risk?”, IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[11] W. Chandrasena, P.G. McLaren, U.D. Annakkage, R.P. Jayasinghe, “Modeling GIC Effects on Power Systems: The Need to Model Magnetic Status of Transformers”, 2003 IEEE Bologna Power Tech Conference, June 23 – 26, 2003, Bologna, Italy

Problems can occur with differential protective relays that are looking to see balanced primary and secondary currents, i.e., the transformer may trip as the primary current becomes disproportionately large (drawing increasingly more reactive current) compared to its secondary current.

Leakage flux is always present in a transformer that is carrying load. Because of the problems that it can otherwise cause, transformer manufacturers design and build their transformers such that the anticipated leakage flux is "managed" and has minimal impact on the long term operation and survivability of the transformer. Leakage flux, however, is never anticipated from the excitation of the transformer. The high peak magnetizing current pulse (red in Figure 3) produces correspondingly higher magnitudes of leakage flux (as given by the red waveform on the left side of Figure 3) that is also rich in harmonics.[12]

The influence of excessive leakage flux on the transformer is generally thermal. Leakage flux in transformers that links any conductive material (including transformer windings and structural parts) will cause induced currents which will result in almost immediate localized, unexpected, and severe heating due to resistive losses. Paint burning off transformer tank walls might be considered an asset owner's best news case example. Transformer designs that implement core bolts are a concern because should the stray flux link such bolts located at the bottom of the windings and cause the surrounding oil to heat to 140°C, this could result in bubble evolution that ultimately fails the transformer. For any given design, a finite element analysis will reveal the leakage flux paths and weaknesses, if any, in the design. If a transformer is lightly loaded, and therefore its operating leakage flux is light as compared to its full load rated flux, the unit may be able to handle the additional leakage flux introduced by GIC.

In summary, a saturated transformer becomes a reactive energy sink, an unexpected inductive load on the system, and behaves more like a shunt reactor.[13] Transformer differential protective relays may trip and remove the transformer from service. Excessive leakage flux can result in detrimental overheating, or in some designs, winding damage due to resulting high winding circulating currents. Separately, the magnetizing current pulse of a GIC inflicted transformer injects significant harmonics into the power system. The resultant impact of these changes in the transformer(s) constitutes the second order effects of GIC.

Second Order Effects of GIC

Many agree that the more concerning impacts of GIC are its indirect effects on the power system and its components. The influence of a transformer morphing into a shunt reactor on the power system is best understood after a review of shunt reactors and capacitors.

Shunt capacitor banks are used to offset inductive effects on the power system (to support voltage) while shunt reactors are used to offset the effects of capacitance on the system (to lower voltage). Typically, shunt capacitors are switched in during periods of high load, and shunt reactors are switched in during periods of light load. The same effects can be achieved, within rating limits, by varying the excitation of generators, i.e., operating them as "synchronous condensers". Static VAR compensators (SVC's), which combine capacitor banks and reactors also provide similar compensation and voltage

[12] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.
[13] It should be noted that upon removal of the DC current, a core will not remain in its saturated state while energized.

support, with very fast automated controls. Many power systems once had dedicated synchronous condensers (rotating machines). However, capacitor banks are cheaper and capacitor technology advanced to the point where reliability became excellent, so synchronous condensers were retired.[14]

Inductive reactance, which is expressed by, $X_L = 2\pi fL$, indicates that as inductance, L, goes down, inductive reactance drops. Saturated transformers have low shunt magnetizing inductance so they draw high currents; they look like shunt reactors on the system, dragging down the system voltage. Capacitive reactance is expressed by, $X_C = 1/(2\pi fC)$. From this, it is easy to see that a capacitor presents as an open circuit (infinite impedance) to DC current; thus the effectiveness of series capacitor blocking in very long transmission lines as a GIC mitigation strategy. Alternatively, as frequency goes up, capacitive reactance drops so capacitor banks have lower impedances to harmonics and draw larger currents when harmonics are present.

While saturated transformers draw large currents, forcing system voltage down (and potentially overloading long transmission lines), capacitor banks also draw large currents due to the presence of resultant harmonics, partially offsetting the inductive effects. Essentially, the saturated transformers are in a tug-of-war with the capacitors on the system. Modern shunt capacitors have very low loss and are therefore less susceptible to transient heating damage due to excess current. However, large currents may affect other components in capacitor bank installations, resulting in damage and unwanted tripping.[15] Voltage imbalance and overvoltage protection may also be "fooled" by harmonic voltage spikes and cause unwanted trips. Finally, overcurrent protection may also operate spuriously in the face of harmonic currents.[16] Similar issues may apply to SVC's. Harmonic filters for SVCs banks create parallel resonances which can exacerbate voltage disturbance issues and result in tripping of the protection devices. [13]

Rotating machines have fairly high thermal inertias, so generators operated as synchronous condensers have a higher probability of staying on line.[13] However, generators can also be affected by GIC currents. These effects include additional heating, damage to rotor components, increased mechanical vibrations and torsional stress due to oscillating rotor flux caused by increased negative sequence harmonic currents. The harmonic content of negative sequence currents can also cause relay alarming, erratic behavior or generator tripping.[17] If VAR resources are exhausted during a GMD event, specifically capacitive voltage support, voltage collapse can occur.

NERC's 2012 Special Reliability Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System provides a block diagram that illustrates the effects of GIC, culminating in a threat to system voltage and angle stability (Figure 5).

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[14] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[15] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[16] B. Bozoki et al., Working Group K-11 of the Substation Protection Subcommittee of the Power System Relaying Committee, IEEE PES, "The Effects of GIC on Protective Relaying," *IEEE Transactions on PowerDelivery*, Vol. 11, No. 2, April 1996, pp. 725-739.

[17] D. Wojtczak and M. Marz, "Geomagnetic Disturbances and the Transmission Grid" http://www.cce.umn.edu/documents/cpe-conferences/mipsycon-papers/2013/geomagneticdisturbancesandthetransmissiongrid.pdf

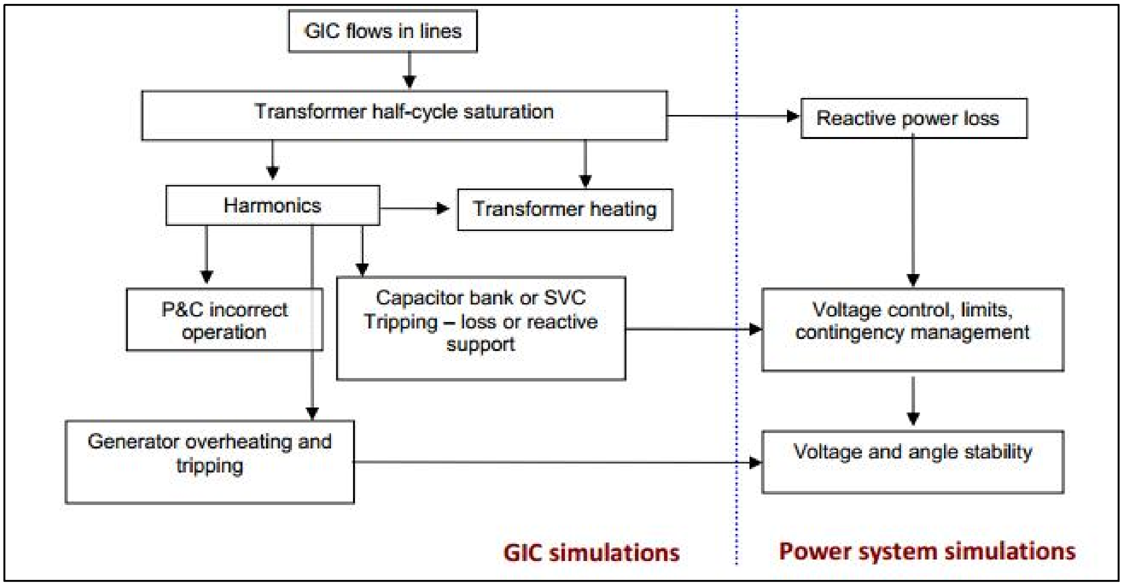

FIGURE 5
From NERC: Effects of GIC in a High Voltage Transmission Network[18]

<u>A Special Dispensation about the Effects of GIC on CTs (and protective relays)</u>;

It is important to have accurate measurements of system state during abnormal operating conditions. For these purposes, the industry has predominantly relied upon conventional instrument transformers (such as a current transformer ("CT"); a potential (or voltage) transformer, which may be inductive ("PT"/"VT") or capacitive ("CCVT"); or a combined current and voltage instrument transformer). An instrument transformer ("IT") is "intended to reproduce in its secondary circuit, in a definite and known proportion, the current or voltage of its primary circuit with the phase relations and waveforms substantially preserved."[19] The electromagnetically induced current or voltage waveform(s) in the secondary circuit(s) of the instrument transformer (IT) should then be of an easily measurable value for the metering or protective devices that are connected as the load, or "burden", on the IT.

In as much as a traditional, "ferromagnetic" IT has a magnetic core, instrument transformers are subject to influence from the presence of GIC much like a power transformer (discussed in the preceding sections). If an IT is pushed to a non-linear region of its saturation curve (i.e., its operating curve), due, for example, to a DC flux shift, the accuracy of the IT will significantly decline. While it is true that ITs typically operate at lower magnetization levels than power transformers because reading accuracy must be maintained in the face of large fault currents (i.e., they have more "built-in margin" on the curve), there is no way of knowing whether the magnitude of GIC in the system is yet enough to saturate the core (despite its margins), or if remanence was pre-existing in the core and already compromising the IT's performance. In short, there will always be uncertainty about the reliability of system state measurements provided by ferromagnetic instrument transformers during a GIC event. Moreover,

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[18] North American Electric Reliability Corporation (NERC) Geomagnetic Disturbance Task Force (GMDTF) Interim Report, "Effects of Geomagnetic Disturbances on the Bulk Power System," February 2012, page 62. http://www.nerc.com/files/2012GMD.pdf

[19] "C37.110-2007 IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes", IEEE, New York, NY April 7, 2008.

when currents and voltages become rich in harmonics, even if the IT is not operating in a saturated state, the accuracy of the measurements will decline. Unfortunately, there is no on-line method of validating whether the instrument transformer is operating in a non-saturated state and, therefore, within its "window of accuracy" (i.e., the pseudo-linear region of its saturation curve at 60 Hz) or in a saturated state and, therefore, outside the realm in which it can accurately reproduce measurements.

Reference 20 provides more details about the variables that impact the performance of conventional instrument transformers.[20]

It is lastly noted that protective relays operate based only on their inputs. If a CT, for example, is supplying a distorted waveform due to the effects of harmonic saturation, the relay may respond in a different, and unwanted, way than it does to nearly sinusoidal inputs.[21]

FERC/NERC Regulation

Federal regulations designed to protect the nation's electric grid from the potentially severe and widespread impact of a geomagnetic disturbance (GMD) are in the process of being adopted. Following several years of study, the Federal Energy Regulatory Commission (FERC) initiated a rulemaking in 2012, the first of its kind, directing NERC to develop and submit for approval Reliability Standards to protect the grid from the impact of GMDs.

In Order No. 779, FERC determined that the risk posed by GMD events, and the absence of Reliability Standards to address GMD events, posed a risk to system reliability that justified its precedent-setting order directive to NERC to develop Reliability Standards to address the issue. In order to expedite the standards-setting process, FERC ordered NERC to develop mandatory standards in two stages, both of which are now underway.

In the first stage, FERC directed NERC to submit Reliability Standards that required owners and operators of the bulk-power system to develop and implement operational procedures to mitigate the effects of GMDs to ensure grid reliability. These operational procedures were considered a "first step" to address the reliability gap and were approved by FERC in June 2014. These standards become mandatory on January 1, 2015.

In the second stage, FERC has directed NERC to provide more comprehensive protection by requiring entities to perform vulnerability assessments and develop appropriate mitigation strategies to protect their facilities against GMD events. These strategies include blocking GICs from entering the grid, instituting specification requirements for new equipment, and isolating equipment that is not cost effective to retrofit. In subsequent orders, FERC has reiterated its expectation that the second stage GMD standard include measures that address the collection, dissemination, and use of GIC data, by NERC, industry, or others, which may be used to develop or improve GMD mitigation methods or to validate GMD models.

Thus, FERC's forthcoming standard is likely to require or strongly encourage the installation of GIC monitoring equipment as a means of assessing vulnerability and as the data source by which GIC

[20] J. Duplessis and J. Barker, "Intelligent Measurement for Grid Management and Control", PACWorld Americas Conference, Raleigh, N.C., September 2013

[21] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

blocking or other protection schemes are to be implemented. The second stage standards including equipment-based GMD mitigation strategies are due to be filed by NERC in January 2015 and are likely to be approved by FERC in mid-2015.

Intensity Modulated Optical Sensing Technology

Intensity modulated optical sensing technology provides the full system visibility, accuracy and stability required to effectively mitigate GIC effects. This cannot be done with the grid's present information infrastructure comprised primarily of ferromagnetic type instrument transformers.

The fundamental solution to accurate information is to find a physical solution that can observe the system without being electrically coupled to the system, or measurand. This concept precludes any of the IT products either currently available or under development. Instead, it requires a completely new approach to measurement.

Starting in the late 90's, the electric power industry began to experiment with optical techniques that used interferometeric wave and phase modulation as the physical underpinnings of an electrically decoupled measurement system. Unfortunately, this equipment has generally failed in field applications due to its extreme sensitivity to temperature and EMI.

To solve this problem, a new approach based on recently declassified military applications has now been adapted to the needs of the electric power grid – thus achieving the objective of a highly accurate and reliable measurement device that is not electrically coupled to the measurand.

How the technology works:

The U.S. Naval Research Lab (NRL) has been a leader in optical sensing research for over 50 years. Similar to the power industry's experience with interferometric sensors[22], the Navy found that the acute temperature and EMI sensitivity of these devices caused them to fail in mission critical, field applications. To solve these problems, the NRL ultimately developed a highly stable, *intensity* modulated optical sensor that has no temperature sensitivity, no susceptibility to EMI, no frequency modulation, and has been proven to operate accurately in very harsh conditions for long periods of time. This technology, vetted over decades, has now been adapted to measure voltage, current, phase and other characteristics of electric phenomena, and can deliver accurate, stable and reliable performance in rigorous field applications on the power system.

An intensity modulated optical monitoring system consists of a transducer that is located within the force field it is measuring, a light source located some distance away, a fiber optic transmitting cable, at least one fiber collector or return cable, and power electronics.

A sensing element is held securely within the transducer; this is a material that is deliberately selected based upon the measuring application and which responds to changes in the force to which it is subjected. This force is characterized by a magnitude and frequency. In the case of acoustic measurements, and as shown in Figure 6, this material is a diaphragm. Physical displacement of the sensor is being directly measured but this movement is ultimately a function of the force (i.e., the measurand) acting upon it.

Light of a known intensity (P_T) from a light-emitting diode (LED) is coupled into an optical fiber for transmission to the sensing element where it is modulated in accordance with the state of the measurand.

[22] As gauged by general polled feedback

Reflected light of a varying intensity (P_R) is collected by at least one return fiber for transmission back to a photo-detector.

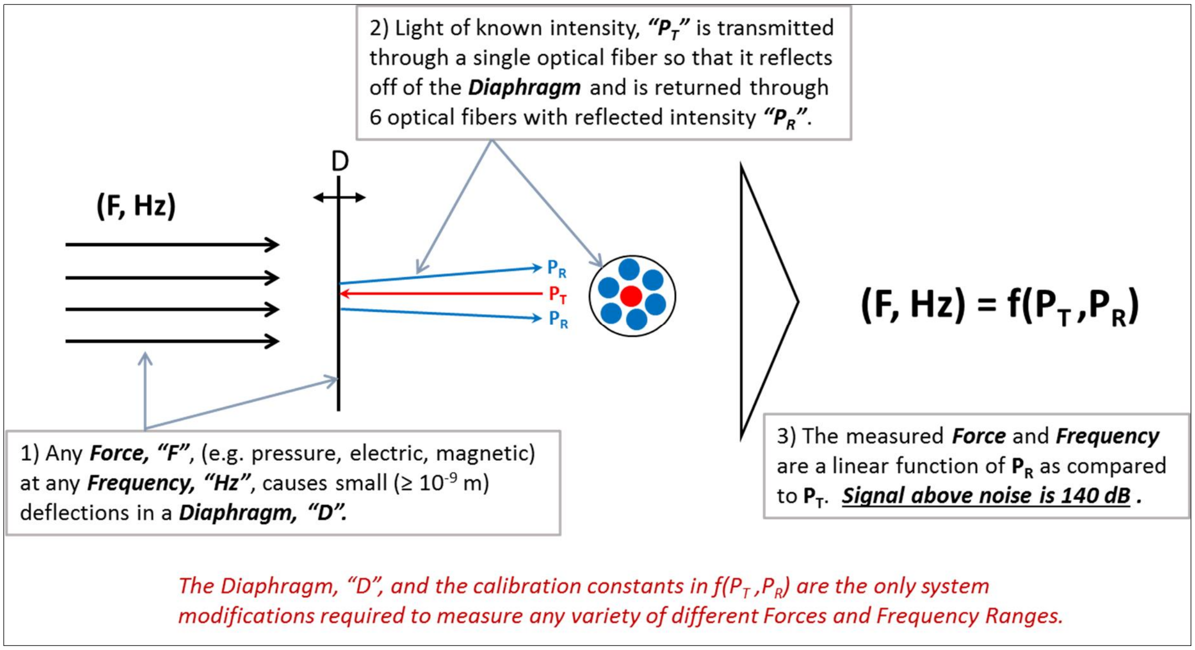

Figure 6
Intensity Modulated Optical Sensing – Fundamental Concept

The intensity of the light returned through the fiber correlates to the force exerted on the sensing element and the frequency with which it is changing. As an example, consider an acoustical measurement. As sound changes, the diaphragm moves and the resultant distance between the fiber probe and the diaphragm changes. Note that the fiber probe is stationary; it is the movement of the sensing element that alters the distance between the probe and the sensor. If that distance becomes smaller by way of displacement of the diaphragm towards the fiber probe, the reflectance changes and the intensity of the reflected light captured by the return fibers decreases (Figure 7). As the distance increases, more reflected light is captured by the return fibers and, consequently, P_R increases (Figure 8).

One transmit fiber and only one return fiber is depicted in Figures 7 and 8. The use of multiple return fibers amplifies the sensitivity of this intensity modulated technology, resulting in the ability to detect displacement changes of the sensing element on the order of 10^{-9} meters.

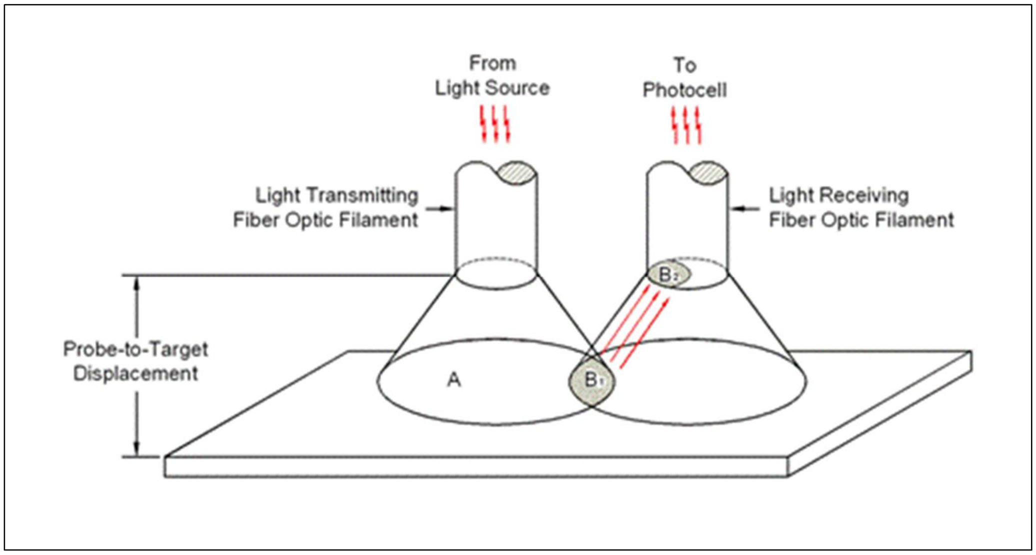

FIGURE 7[23]

P_R Decreases as Displacement between Probe and Diaphragm Decreases

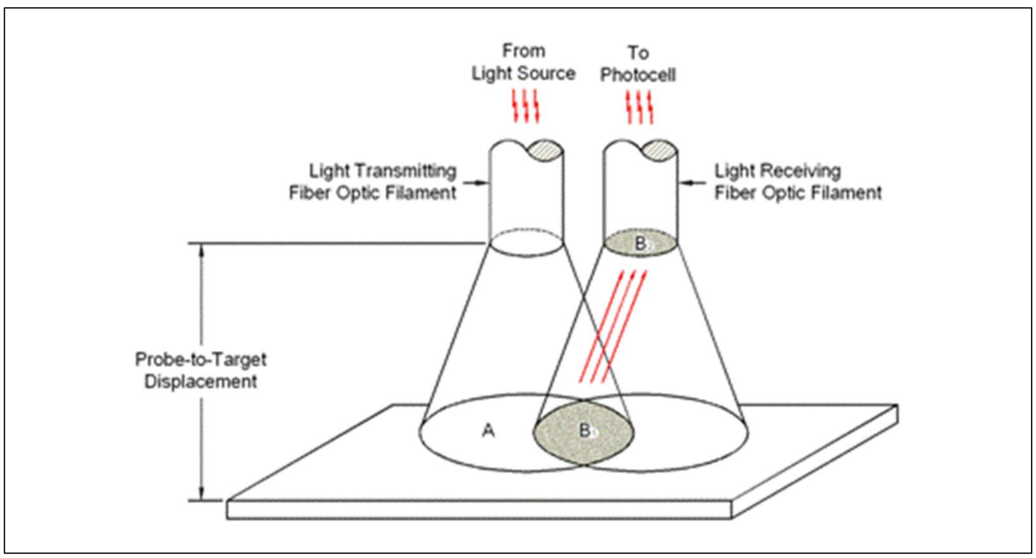

FIGURE 8[24]

P_R Increases as Displacement between Probe and Membrane Increases

Adaptation

Adapting Intensity Modulated Optical Sensors to Measure Electrical Phenomena:

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[23] Yury Pyekh, "Dynamic Terrain Following: NVCPD Scanning Technique Improvement", Fig. 3.7, Thesis Presented to the Academic Faculty of Georgia Institute of Technology, August 2010.

[24] Yury Pyekh, "Dynamic Terrain Following: NVCPD Scanning Technique Improvement", Fig. 3.8, Thesis Presented to the Academic Faculty of Georgia Institute of Technology, August 2010.

Laws of physics are used to adapt the intensity modulated (IM) optical sensors to measure current and voltage. For example, principles of Lorentz's Force are applied to build the IM optical (AC) current sensor.

A Lorentz force, given by F = BLI and illustrated in Figure 9, will result when a current (I) carrying conductor passes through a non-varying magnetic field with flux density, B for some length, L.

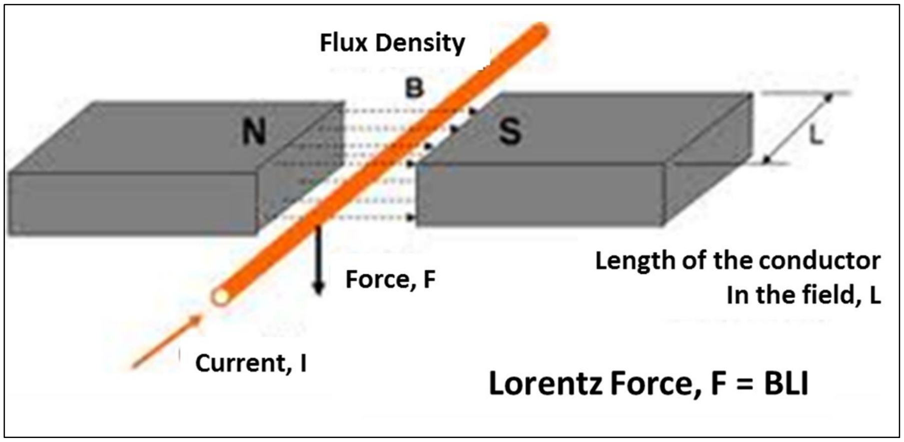

FIGURE 9
Lorentz Law

Accordingly, the current sensing element (Figure 10) connects to the line conductor; as current changes, variations in the Lorentz Force will result in the physical displacement of the sensing element. The intensity of light reflected back will therefore alter proportionally to the changes in the current.

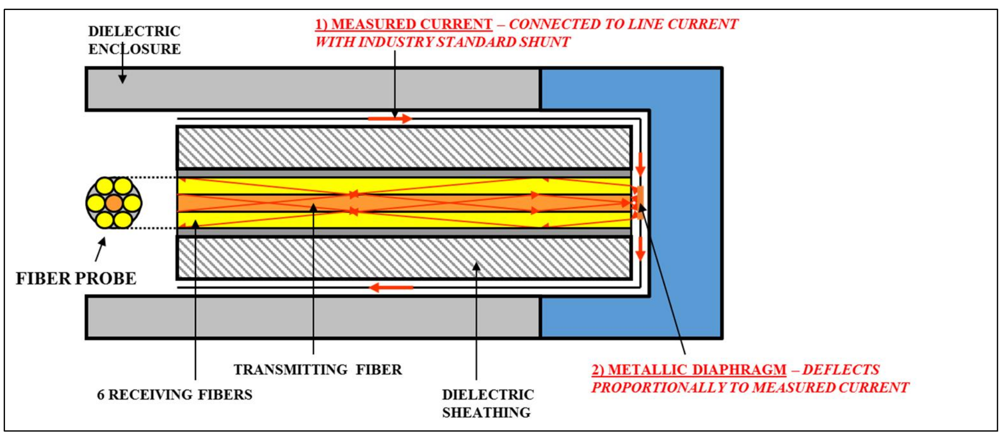

FIGURE 10
Intensity Modulated Fiber Optic Current Sensor

For voltage measurements, the selection of the sensing element is key. Here, a piezoelectric material is selected that has very stable physical characteristics that vary in a known way as the electric field in which the material is placed varies. A reflected surface affixed to the end of the sensing element will physically displace, therefore, as the material deflects relative to changes in the electric field.

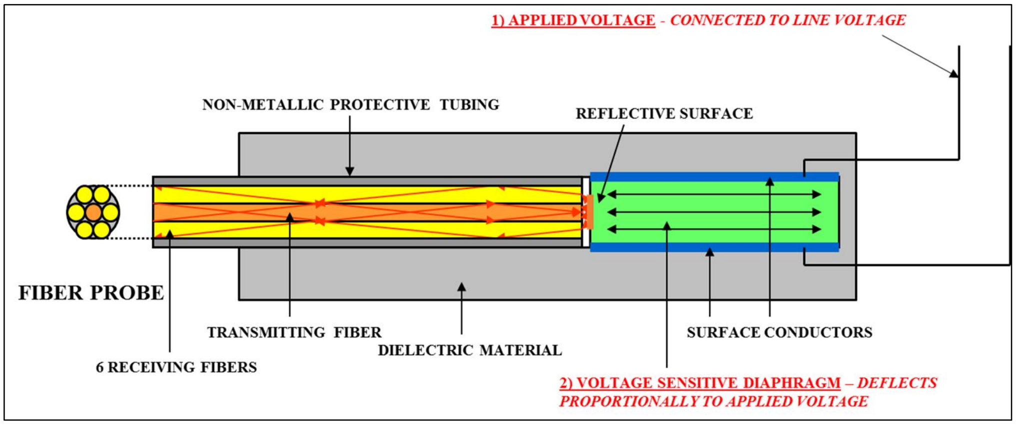

FIGURE 11
Intensity Modulated Fiber Optic Voltage Sensor

The IM optical current and voltage sensors are housed in a common transducer. The physical dimensions of these sensors are very small; the length of a sensor, its maximum dimension, is typically shorter than a few inches. This makes it possible to hold several sensors within one transducer, including IM optical temperature sensors.

IM optical sensing technology is adapted differently to measure DC current and voltage but is not discussed in this paper.

Advantages

Accurate, Repeatable Measurement over an Extremely Wide Range of Values and Frequencies

The fact that Intensity Modulated (IM) optical sensing is passive, non-ferromagnetic and non-interferometry based is central to why this technology delivers a step-change improvement in performance over both conventional instrument transformers and interferometry-based optical equipment.

First, because of its passivity, an IM optical transducer does not disturb the (power) system it observes. The sensing element is non-conductive and the transducer is electrically decoupled from the grid; light is the 'exchange medium' of the transducer and an electrical system is not altered by light. The transducer therefore 'sees' exactly what exists on the power system and this creates notably higher accuracy than what can be achieved by even the most accurate of metering class instrument transformers.

Second, because IM optical sensing is electrically de-coupled and is not ferromagnetic, traditional burdens have no influence on the transducer and the power system cannot negatively impact its measuring capability. IM optical sensors have no saturation curve; their equivalent operating "curve", and therefore performance, is perfectly linear throughout their wide measurement range. By removing variables introduced by system and burden influences, which have plagued the performance of conventional ITs in unpredictable ways for decades, the industry gains automatic assurances that the IM optical transducer is maintaining the accuracy it should at all times. This creates consistent accuracy and therefore, repeatability.

A third advantage of IM optical sensors' non-ferromagnetic based operation is that frequency has no influence on its measuring capabilities. While varying the frequency does alter the shape of a saturation curve that defines the operating characteristics of a conventional IT, it has no effect on the linear operating curve of an IM optical sensor. IM sensors can measure voltage and current at frequencies from quasi-DC to several thousand Hertz. There are no concerns about resonant frequencies associated with inductive and capacitive voltage transformers. This measuring technology therefore affords the power industry the opportunity to view a broad range of non-fundamental frequency components with the same accuracy as measurements at the fundamental frequency (50/60 Hz) and therefore, to perform incredibly insightful power quality studies.

While the pseudo-linear range of a conventional IT's saturation curve is not large, affording only an approximate 20 dB dynamic range, the linear range of operation of an IM optical sensor delivers an approximate >130 dB dynamic range. This means that a single IM optical current sensor, for example, can measure an extremely large fault current, and at once, an exceptionally small harmonic current with identical accuracy. An IM optical system's measuring range is only limited by its noise floor, which is much lower than any other conventional or non-conventional field measurement device that is currently available.

Figure 12 gives a visual representation of the range of (current/voltage) magnitudes over which a conventional IT will yield accurate measurements (the vertical height of the blue shaded area at 60 HZ) and the limiting influence of frequency on a conventional IT's accurate measuring capabilities (as given by the diminishing height of the blue-shaded area as the frequency decreases/increases). In contrast, the much broader, frequency independent, and notably more accurate measuring capabilities of an IM monitoring system are indicated by the encompassing white backdrop that frames the graph in Figure 12.

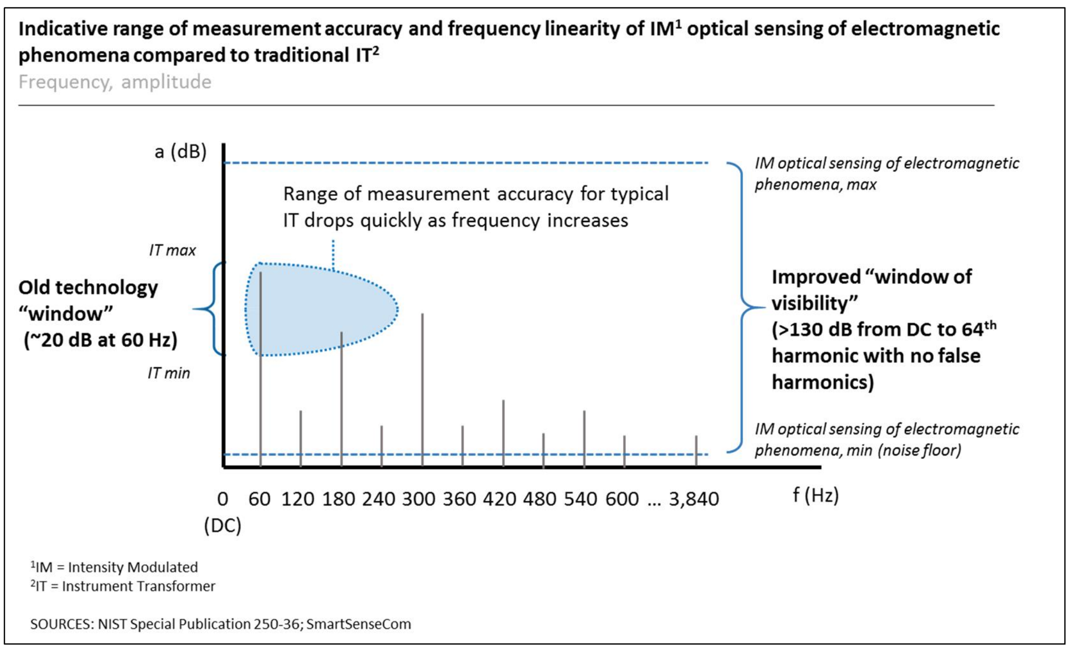

FIGURE 12
Accuracy/ Linearity as a Function of Frequency
(For an IM Optical Monitoring System versus a Conventional IT)

Safety and Risk Reduction

A separate, but equally important, advantage of passive IM optical sensors is safety and risk reduction in the unlikely event of the IM optical system's failure. With a conventional IT, the electrical grid extends all the way to the meter or protective device and the possibility exists for workers to be injured or even killed if they were to inadvertently come into contact with an open-circuited CT secondary. In contrast, the equivalent "secondary" side of an IM optical transducer is fiber optic cable carrying light. It presents no safety hazard. Moreover, should a conventional IT fail, it typically brings the circuit down with it, either due to catastrophic fire or a fault that trips the breaker. In comparison, the IM has no influence on the power system it is observing, and if it should fail, the power system would typically continue to operate as usual.

An additional benefit of being non-ferromagnetic is that periodic field testing to verify operating characteristics and insulation integrity is not necessary for an IM optical transducer. In fact, because an IM optical transducer is electrically decoupled from the grid, there is no requirement for the use of dielectric materials such as oil or SF6 in the device. The combination of these factors reduces O&M costs and expedites safe system restoration after outages.

"IM" Optical Sensing as a Comprehensive Solution to Identifying and Measuring Impacts of GIC

The concerns about GMD are justified and the effects of GIC well documented. The path forward becomes clear after reflection upon just a few of the industry comments about GIC:

- "Accurate estimation of the VAR consumption of the transformer during a GMD event is critical for proper mitigation of effects of GIC on power system stability."
- "Increase in VAR demand is one of the major concerns during a GMD event. The loss of reactive power could lead to system voltage collapse if it is not identified and managed properly."
- "…the magnetizing current pulse injects significant harmonics into the power system which can have a significant impact on shunt capacitor banks, SVCs and relays and could compromise the stability of the grid."

The GIC mitigation solution lies in the ability to quantify its effects in real time. The industry has not been able to do that up to now with the measuring devices available. IM optical monitoring systems change this.

An AC current and voltage IM optical transducer must be installed on the high-voltage side of a susceptible transformer. This will measure the VAR consumption of the transformer as well as any harmonics generated given the operating state of the transformer, well into the kHz range. A DC current IM optical transducer would be installed on the grounded neutral connection of the transformer. IM optical technology provides for accuracies of approximately one percent at low magnitude DC currents, 1 – 25A, allowing exacting correlation between DC currents and concurrently observed effects on the transformer (reactive energy consumption and harmonic profile).

Because of the many variables that contribute to the vulnerability of the transformer and connected power system, even given the same GIC magnitude, the transformer/system response is expected to be different. For this reason, it is not enough to install a simple DC current monitor, such as a Hall Effect sensor, on the neutral ground connection of a transformer. Even if one were to look past the instability of such devices, particularly at low DC current levels (< 25A), a DC measurement alone does not afford reliable predictability about the associated power system impact.

Conclusion

The negative impacts of geomagnetically induced currents ("GIC") are understood at a high level. GIC flow negatively impacts certain power transformers causing half-cycle saturation that leads to increased demand for reactive power, generation of harmonics, and transformer heating. This in turn negatively impacts electric power transmission systems; at its worse, causing grid instability due to voltage collapse, misoperation of protection equipment (e.g., capacitor banks, overcurrent relays), damage to sensitive loads due to poor power quality, and/or thermal damage to the transformer. However, better system visibility is required to develop effective GIC mitigation strategies. For example, what is the actual change in reactive power and the harmonic generation profile at a specific location when GIC is present? How will the surrounding transmission system actually respond to these changes?

It is important to have accurate measurements of system state during abnormal operating conditions. Unfortunately, traditional ferromagnetic-type instrument transformers are at risk of being affected by GIC conditions too. There is no way of validating, in real time and while energized, whether an instrument transformer is saturated or not, so it is possible that information provided to protective devices may be riddled with error on the magnitude of over 12 percent. Moreover, classical instrument transformers do not have the ability to reproduce harmonics with any guaranteed accuracy (even when demagnetized) much beyond the 3rd harmonic.

The GMD/GIC phenomena is a prime example where the industry's inability to sufficiently measure will leave it struggling to manage unless we embrace change. A solution to gain full (and stable!) system visibility was introduced. It is an optical solution called Intensity Modulated (IM) optical measuring; it resolves the grid's present-day measuring inadequacies and is different than earlier optical techniques which, while promising, have proven to be unstable under field conditions due to extreme temperature instability and electromagnetic interference. An IM optical system was described along with some example adaptations for its use in measuring electrical phenomena. Advantages of IM optical transducers, rooted in their passivity and non-ferromagnetic characteristics, were enumerated. These include a step-change improvement in accuracy; hardening to otherwise influencing 'environmental' variables resulting in stability and consistency in measurements, and therefore, repeatability; the ability to observe the power system more comprehensively than ever before through one transducer; and significant enhancement in personnel and system safety.

The GIC mitigation solution lies in the ability to quantify its effects in real time. This can be accomplished through intensity modulated optical monitoring systems.

Group Comments on NERC Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

November 21, 2014

Draft standard TPL-007-1, "Transmission System Planned Performance for Geomagnetic Disturbance Events," is not a science-based standard. Instead, the apparent purpose of standard TPL-007-1 is to achieve a preferred policy outcome of the North American Electric Reliability Corporation (NERC) and its electric utility members: avoidance of installation of hardware-based protection against solar storms. The draft standard achieves this apparent purpose through a series of scientific contrivances that are largely unsupported by real-world data. Potential casualties in the millions and economic losses in trillions of dollars from severe solar storms instead demand the most prudent science-based standard.

A 2010 series of comprehensive technical reports, "Electromagnetic Pulse: Effects on the U.S. Power Grid"[1] produced by Oak Ridge National Laboratory for the Federal Energy Regulatory Commission in joint sponsorship with the Department of Energy and the Department of Homeland Security found that a major geomagnetic storm "could interrupt power to as many as 130 million people in the United States alone, requiring several years to recover."

A 2013 report produced by insurance company Lloyd's and Atmospheric and Environmental Research, "Solar Storm Risk to the North American Electric Grid,"[2] found that:

> "A Carrington-level, extreme geomagnetic storm is almost inevitable in the future. While the probability of an extreme storm occurring is relatively low at any given time, it is almost inevitable that one will occur eventually. Historical auroral records suggest a return period of 50 years for Quebec-level storms and 150 years for very extreme storms, such as the Carrington Event that occurred 154 years ago."
>
> "The total U.S. population at risk of extended power outage from a Carrington-level storm is between 20-40 million, with durations of 16 days to 1-2 years. The duration of outages will depend largely on the availability of spare replacement transformers. If new transformers need to be ordered, the lead-time is likely to be a minimum of five months. The total economic cost for such a scenario is estimated at $0.6-2.6 trillion USD."

A 2014 paper published in the Space Weather Journal, "Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment"[3] by C. J. Schrijver, R. Dobbins, W. Murtagh, and S.M. Petrinec found:

> "We find that claims rates are elevated on days with elevated geomagnetic activity by approximately 20% for the top 5%, and by about 10%for the top third of most active days ranked by daily maximum variability of the geomagnetic field."
>
> "The overall fraction of all insurance claims statistically associated with the effects of geomagnetic activity is 4%."

> "We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude."

Given the extreme societal impact of a major solar storm and large projected economic losses, it is vital that any study by NERC in support of standard TPL-007 be of the highest scientific caliber and rigorously supported by real-world data. The unsigned white papers of the NERC Standard Drafting Team fail scientific scrutiny for the following reasons:

1. The NERC Standard Drafting Team contrived a "Benchmark Geomagnetic Disturbance (GMD) Event"[4] that relies on data from Northern Europe during a short time period with no major solar storms instead of using observed magnetometer and Geomagnetically Induced Current (GIC) data from the United States and Canada over a longer time period with larger storms. This inapplicable and incomplete data is used to extrapolate the magnitude of the largest solar storm that might be expected in 100 years—the so-called "benchmark event." The magnitude of the "benchmark event" was calculated using a scientifically unproven "hotspot" conjecture that averaged the expected storm magnitude downward by an apparent factor of 2-3. This downward averaging used data collected from a square area only 500 kilometers in width, despite expected impact of a severe solar storm over most of Canada and the United States.
2. The NERC Standard Drafting Team contrived a table of "Geomagnetic Field Scaling Factors" that adjust the "benchmark event" downward by significant mathematical factors dependent on geomagnetic latitude. For example, the downward adjustment is 0.5 for Toronto at 54 degrees geomagnetic latitude, 0.3 for New York City at 51 degrees geomagnetic latitude, and 0.2 for Dallas at 43 degrees geomagnetic latitude. These adjustment factors are presented in the whitepaper in a manner that does not allow independent examination and validation.
3. The NERC Standard Drafting Team first contrived a limit of 15 amps of GIC for exemption of high voltage transformers from thermal impact assessment based on limited testing of a few transformers. When the draft standard failed to pass the second ballot, the NERC Standard Drafting Team contrived a new limit of 75 amps of GIC for exemption of transformers from thermal impact assessment, again based on limited testing of a few transformers. The most recent version of the "Screening Criterion for Transformer Thermal Impact Assessment"[5] whitepaper uses measurements from limited tests of only three transformers to develop a model that purports to show all transformers could be exempt from the thermal impact assessment requirement. It is scientifically fallacious to extrapolate limited test results of idiosyncratic transformer designs to an installed base of transformers containing hundreds of diverse designs.

The above described contrivances of the NERC Standard Drafting Team are unlikely to withstand comparison to real-world data from the United States and Canada. Some public GIC data exists for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper "Benchmark Geomagnetic Disturbance Event Description." Some public disclosures of transformer failures during and shortly after solar storms exist for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper "Screening Criterion for Transformer Thermal Impact Assessment."

NERC is in possession of two transformer failure databases.[6] [7] This data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Screening Criterion for Transformer Thermal Impact Assessment. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on transformer failures, contrary to Section 6.0 of the NERC Standards Processes Manual, "Processes for Conducting Field Tests and Collecting and Analyzing Data."[8]

U.S. and Canadian electric utilities are in possession of GIC data from over 100 monitoring locations, including several decades of data from the EPRI SUNBURST system.[9] This GIC data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Benchmark Geomagnetic Disturbance Event. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on measured GIC, contrary to Section 6.0 of the NERC Standards Processes Manual, "Processes for Conducting Field Tests and Collecting and Analyzing Data."[10]

The NERC whitepaper "Benchmark Geomagnetic Disturbance Event Description" contains "Appendix II – Scaling the Benchmark GMD Event," a system of formulas and tables to adjust the Benchmark GMD Event to local conditions for network impact modeling. Multiple comments have been submitted to the Standard Drafting Team showing that the NERC formulas and tables are inconsistent with real-world observations during solar storms within the United States.[11] [12] [13] While the NERC Standard Processes Manual requires that the Standard Drafting Team "shall make an effort to resolve each objection that is related to the topic under review," the Team has failed to explain why its methodology is inconsistent with measured real-world data.[14]

Even the most rudimentary comparison of measured GIC data to the NERC "Geomagnetic Field Scaling Factors" shows the methodology of "Appendix II—Scaling the Benchmark GMD Event" of whitepaper "Benchmark Geomagnetic Disturbance Event Description" is flawed. For example, this comment submitted in standard-setting by Manitoba Hydro:

> "GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC's of 24.5 Amps and 20.2 Amps. "[15]

In the above instance, if the NERC "Geomagnetic Field Scaling Factors" were correct and all other factors were equal, the measured GIC amplitude at 45 degrees geomagnetic latitude should have been 1 Amp (5.3 Amps times scaling factor of 0.2). Were other GIC data to be made publicly available, it is exceedingly likely that the "Geomagnetic Field Scaling Factors" would be invalidated, except as statistical averages that do not account for extreme events. Notably, the above observation of Manitoba Hydro is consistent with the published finding of C. J. Schrijver, et. al. that "We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude."

The EPRI SUNBURST database of GIC data referenced in the above Manitoba Hydro comment should be made available for independent scientific study and should be used by the NERC Standard Drafting Team to correct its methodologies.

American National Standards Institute (ANSI)-compliant standards[16] are required by the NERC Standard Processes Manual. Because the sustainability of the Bulk Power System is essential to protect and promptly restore operation of all other critical infrastructures, it is essential that NERC utilize all relevant safety and reliability-related data supporting assessments of geomagnetic disturbance impacts on "critical equipment" and benefits of hardware protective equipment. Other ANSI standards depend upon and appropriately utilize safety-related data on relationships between structural design or protective equipment and the effective mitigation of earthquakes, hurricanes, maritime accidents, airplane crashes, train derailments, and car crashes.

Given the large loss of life and significant economic losses that could occur in the aftermath of a severe solar storm, and the scientific uncertainly around the magnitude of a 1-in-100 solar storm, the NERC Standard Drafting Team should have incorporated substantial safety factors in the standard requirements. However, the apparent safety factor for the "Benchmark GMD Event" appears to be only 1.4 (8 V/km geoelectric field used for assessments vs. 5.77 V/km estimated).

The NERC Standard Processes Manual requires that the NERC Reliability Standards Staff shall coordinate a "quality review" of the proposed standard.[17] Any competent quality review would have detected inconsistencies between the methodologies of the "Benchmark Geomagnetic Disturbance Event Description" and real world data submitted in comments to the Standard Drafting Team. Moreover, any competent quality review would have required that the Standard Drafting Team use real-world data from the United States and Canada, rather than Northern Europe, in developing the methodologies of the "Benchmark Geomagnetic Disturbance Event Description" and "Screening Criterion for Transformer Thermal Impact Assessment."

Draft standard TPL-007-1 does not currently require GIC monitoring of all high voltage transformers nor recording of failures during and after solar storms.[18] These requirements should be added given the still-developing scientific understanding of geomagnetic disturbance phenomena and its impact on high voltage transformers and other critical equipment.

Going forward, data on observed GIC and transformer failures during solar storms should be publicly released for continuing scientific study. NERC can and should substitute a science-based standard to model the benefits and impacts on grid reliability of protective hardware to prevent long-term blackouts due to solar geomagnetic storms.

Submitted by:

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Thomas S. Popik
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Wm. R. Harris

William R. Harris
International Lawyer
Secretary, Foundation for Resilient Societies

G H Baker

Dr. George H. Baker
Professor Emeritus, James Madison University
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Andrea Boland

Representative Andrea Boland
Maine State Legislature
Sanford, ME (D)

William R. Graham

Dr. William R. Graham
Chair of Congressional EMP Commission and
former Assistant to the President for Science and Technology
Director, Foundation for Resilient Societies

W. H. Joyce
C.E.O
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1531 Alton Rd
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Endnotes:

[1] "Electromagnetic Pulse: Effects on the U.S. Power Grid," Oak Ridge National Laboratory (June 2010) available at http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Executive_Summary.pdf.

[2] "Solar Storm Risk to the North American Electric Grid," Lloyd's and Atmospheric and Environmental Research (2013) available at https://www.lloyds.com/~/media/lloyds/reports/emerging%20risk%20reports/solar%20storm%20risk%20to%20the%20north%20american%20electric%20grid.pdf.

[3] "Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment," C. J. Schrijver, R. Dobbins, W. Murtagh, and S.M. Petrinec (June 2014) available at http://arxiv.org/abs/1406.7024.

[4] "Benchmark Geomagnetic Disturbance Event Description," NERC Standard Drafting Team (October 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Benchmark_GMD_Event_Oct28_clean.pdf.

[5] "Screening Criterion for Transformer Thermal Impact Assessment," NERC Standard Drafting Team (October 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/GMD_Thermal_screening_Oct27_clean.pdf.

[6] "Generating Availability Data System (GADS)," NERC (Undated) available at http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

[7] "Transmission Availability Data System (TADS),"NERC (Undated) available at http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx.

[8] "Standard Processes Manual, Version 3," NERC (June 26, 2013), page 28, available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[9] "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND," Foundation for Resilient Societies (August 2014) available at http://www.resilientsocieties.org/images/Resilient_Societies_Additional_Facts081814.pdf.

[10] "Standard Processes Manual, Version 3," NERC (June 26, 2013), page 28, available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[11] Comment of, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard," J. Kappenman and W. Radasky (July 30, 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/WhitePaper_NERC_Model_Validation_07302014.pdf.

[12] "Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1," J. Kappenman and C. Birnbach (October 10, 2014), available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/GMD_comments_received_10152014_final.pdf.

[13] "Response to NERC Request for Comments on TPL-007-1," Foundation for Resilient Societies (October 10, 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/GMD_comments_received_10152014_final.pdf.

[14] Standard Processes Manual, Version 3," NERC (June 26, 2013), page 4, available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf, page 4.

[15] "Comment of Manitoba Hydro" Joann Ross, (October 10, 2014), http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/GMD_comments_received_10152014_final.pdf.

[16] "American National Standards Institute, Essential Requirements: Due process requirements for American National Standards," ANSI (January 2014) available at: http://publicaa.ansi.org/sites/apdl/Documents/Standards%20Activities/American%20National%20Standards/Procedures,%20Guides,%20and%20Forms/2014_ANSI_Essential_Requirements.pdf .

[17] "Standard Processes Manual, Version 3," NERC (June 26, 2013), page 20, available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[18] "TPL-007-1 — Transmission System Planned Performance for Geomagnetic Disturbance Events," NERC Standard Drafting Team (October 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/tpl_007_1_20141027_clean.pdf.

Supplemental Comments of the Foundation for Resilient Societies on NERC Standard TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events November 21, 2014

The Foundation for Resilient Societies, Inc. [hereinafter "Resilient Societies"] separately files today, November 21, 2014 Group Comments that assert multiple failures, both procedural and substantive, that result in material noncompliance with ANSI Procedural Due Process, and with NERC's Standard Processes Manual Version 3, effective on June 26, 2013.

In this separate Supplemental Comment, Resilient Societies incorporates as its concerns the material in comments on NERC Standard TPL-007-1 submitted by John Kappenman and William Radasky (July 30, 2014); John Kappenman and Curtis Birnbach (October 10, 2014); John Kappenman (2 comments dated November 21, 2014); and EMPrimus (November 21, 2014).

We reserve the right to utilize all other comments filed in the development of this standard in a Stage 1 Appeal under NERC's Standard Processes Manual Version 3. In particular but not in limitation, we assert that NERC fails to collect and make available to all GMD Task Force participants and to utilize essential relevant data, thereby causing an unscientific, systemically biased benchmark model that will discourage cost-effective hardware protection of the Bulk Power System; that NERC fails to fulfill the obligations under ANSI standards and under the Standard Processes Manual to address and where possible to resolve on their merits criticisms of the NERC Benchmark GMD Event model. Moreover, if the NERC Director of Standards and Standards Department fail to exercise the "quality control" demanded by the Standard Processes Manual, this will also become an appealable error if the standard submitted on October 27 and released on October 29, 2014 becomes the final standard for the NERC ballot body.

Moreover, an essential element of quality control for NERC standard development and standard promulgation is that the Standard comply with the lawful Order or Orders of the Federal Energy Regulatory Commission. To date, no element of the standard performs the cost-benefit mandate of FERC Order. No. 779.

Resilient Societies hereby refers the Standards Drafting Team and the NERC Standards Department to the filing today, November 21, 2014 of Item 31 in Maine Public Utilities Commission Docket 2013-00415. This filing is publicly downloadable. Appendix A to this filing of as Draft Report to the Maine PUC on geomagnetic disturbance and EMP mitigation includes an assessment of avoided costs, hence financial benefits of installing neutral ground blocking devices, including a range of several devices (Central Maine Power) to as many as 18 neutral ground blocking, and GIC monitors (EMPrimus Report, November 12, 2014, Appendix A in the Maine PUC filing of November 21, 2014). Cost-benefit analysis could and should be applied on a regional basis, in the NERC model and with criteria for application by NERC registered entities. NERC has failed to fulfill its mandate, with the foreseeable effect of suppressing public awareness of the benefits resulting from blockage of GICs to entry through high voltage transmission lines into the Bulk Power System. Another foreseeable result is economic harm to those companies that have invested capital in the development of GMD hardware protection devices and GIC monitors. We incorporate by reference the materials in Maine PUC Docket 2013-00415, Items 30 and 31, filed and publicly retrievable online in November 2014.

Finally, we express concern that the combination of NERC Standards in Phase 1 and in Phase 2, providing no mandatory GIC monitor installations and data sharing with Regional Coordinators, and with state and federal operations centers, effectively precludes time-urgent mitigation during severe solar storms despite timely reports to the White House Situation Room.

NERC has effectively created insuperable barriers to fulfill the purposes of FERC Order No. 779. Without significant improvements that encourage situational awareness by Generator Operators and near-real-time data to mitigate the impacts of solar geomagnetic storms, the only extra high voltage transformers that can be reliably protected will be those with installed hardware protection. Yet this defective standard will provide false reassurance that no hardware protection is required. Also, the scientifically defective NERC model may also preclude regional cost recoveries for protective equipment, by falsely claiming that no protective equipment is required under the assessment methodologies in the standard.

Hence irreparable harm to the reliability of the Bulk Power System, and to the residents of North America, is a foreseeable result of the process and substantive result of this standard.

Respectfully submitted by:

Submitted by:

Thomas S. Popik
Chairman
Foundation for Resilient Societies

William R. Harris
International Lawyer
Secretary, Foundation for Resilient Societies

Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Mitigation

The Geomagnetic Disturbance (GMD) Mitigation Standard Drafting Team (SDT) thanks all commenters who submitted comments on the standard. Project 2013-03 is developing requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in FERC Order No. 779:

- EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014. This first stage standard in the project will require applicable registered entities to develop and implement Operating Procedures.

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance events is being developed to meet the Stage 2 directives. The proposed standard will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. If the assessments identify potential impacts, the standard(s) will require the registered entity to develop corrective actions to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

TPL-007-1 was posted for a 25-day public comment period from October 28, 2014 through November 21, 2014. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 50 sets of comments, including comments from approximately 100 individuals from approximately 70 companies representing all 10 Industry Segments as shown in the table on the following pages.

Summary Consideration:

The SDT appreciates the review and constructive comments provided by stakeholders. This active participation is critical to meeting the project scope outlined in the Standard Authorization Request (SAR) and all FERC directives prior to the January 21, 2015 filing deadline.

In response to stakeholder comments, the SDT made only clarifying and non-substantive changes to the proposed standard and supporting material as follows:

TPL-007-1:

- Requirement R1: corrected VRF terminology from "Low" to "Lower."
- Requirement R6: revised Part 6.4 to clarify that the thermal assessments must be performed within 24 calendar months of receipt of GIC flow information specified in Requirement R5, Part 5.1.

- Corresponding change was made to the VSL for Requirement R6.
- Rationale boxes and the application guidelines section were revised for clarity.
- Punctuation and grammatical changes were made throughout the standard.

Screening Criterion for Transformer Thermal Impact Assessment White Paper:

- added clarification on page 3 to indicate that the stated temperature refers to full load bulk oil temperature.
- Corrected table numbering and the example on page 8.

All comments submitted may be reviewed in their original format on the standard's project page.
If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	John Allen	Iberdrola USA			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Julie King	New York State Electric & Gas	NPCC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3

3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Noertheast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Wayne Sipperly	New York Power Authority	NPCC	5
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
15.	Lee Pedowicz	Northeast Power Coordinating Council	NA - Not Applicable	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

3.	Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Edward Bedder	Orange & Rockland Utilities	NPCC	NA

4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X		X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6

6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

5.	Group	Thomas Popik	Interested Parties on NERC Standard TPL-007-1								X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Harris	Foundation for Resilient Societies	NA - Not Applicable	8
2.	George Baker	Foundation for Resilient Societies	NA - Not Applicable	8
3.	William Graham	Foundation for Resilient Societies	NA - Not Applicable	8
4.	Andrea Boland	Maine State Legislature	NA - Not Applicable	9
5.	William Joyce	Advanced Fusion Systems	NA - Not Applicable	8
6.	John Kappenman	Storm Analysis Consultants	NA - Not Applicable	8

6.	Group	Phil Hart	Associated Electric Cooperative, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

7.	Group	Don Hargrove	OG&E	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	OG&E	SPP	1

2.	Leo Staples	OG&E	SPP	3, 5
3.	Jerry Nottnagel	OG&E	SPP	6

8.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

9.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

10.	Group	David Greene	SERC PSS										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1, 3
2.	Jim Kelley	PowerSouth	SERC	1, 5
3.	Phil Kleckley	SCE&G	SERC	1, 3, 5, 6
4.	Shih-Min Hsu	Southern Company	SERC	1, 5

11.	Group	Brian Van Gheem	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection

1.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2.	John Shaver	Arizona Electric Power Cooperative	WECC	1, 4, 5
3.	John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
4.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
5.	Ginger Mercier	Prairie Power, Inc.	SERC	3
6.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
7.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
8.	Ryan Strom	Buckeye Power, Inc.	RFC	3, 4, 5
9.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

12.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Gary Baker		FRCC	3
3.	John Babik		FRCC	5

13.	Group	Kathleen Black	DTE Electric			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	David Szulczewski	Relay Engineering	RFC	

14.	Group	Aaron Gregory	SmartSenseCom, Inc.		X								

N/A

15.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

16.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

N/A

17.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	Transmission Planning	WECC	1
2.	Richard Becker	Substation Engineering	WECC	1
3.	Jim Burns	Technical Operations	WECC	1
4.	Michelle Cowan	Customer Service Engineering	WECC	1

18.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

19.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A													
20.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X			X				
21.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
22.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
23.	Individual	John Bee	Exelon and its Affiliates	X		X		X					
24.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
25.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
26.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
27.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X				X	X				
28.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
29.	Individual	David Kiguel	David Kiguel								X		
30.	Individual	Joe Seabrook	Puget Sound Energy, Inc.	X		X		X		X			
31.	Individual	Thomas Lyons	OMU										
32.	Individual	Nick Vtyurin	Manitoba Hydro	X		X		X	X				
33.	Individual	Thomas Foltz	American Electric Power	X		X			X				
34.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				

35.	Individual	David Jendras	Ameren	X		X		X	X				
36.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
37.	Individual	Terry Volkmann	Volkmann Consulting, Inc								X		
38.	Individual	Mr. Tracy Rolstad	Avista Utilities	X		X							
39.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
40.	Individual	Trevor Schultz	Idaho Power Company	X									
41.	Individual	Michiko Sell	Public Utility District No. 2 of Grant County, WA	X		X	X	X	X			X	
42.	Individual	Anthony Jablonski	ReliabilityFirst										X
43.	Individual	Mark Wilson	Independent Electricity System Operator		X								
44.	Individual	Richard Vine	California ISO		X								
45.	Individual	Texas Reliability Entity, Inc	Texas Reliability Entity, Inc										X
46.	Individual	Erika Doot	Bureau of Reclamation	X				X					
47.	Individual	Bill Temple	Northeast Utilities	X									
48.	Individual	Thomas Popik	Foundation for Resilient Societies								X		
49.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
50.	Individual	Charles Yeung	Southwest Power Pool Inc		X								

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
Omaha Public Power District	Agree	The Omaha Public Power District (OPPD) supports comments submitted by the Midwest Reliability Organization's (MRO) NERC Standards Review Forum (NSRF). Additionally, OPPD doesn't believe this standard should be approved prior to the industry seeing the "NERC Transformer Modeling Guide.
Independent Electricity System Operator	Agree	NPCC Reliability Standards Committee
Southwest Power Pool Inc	Agree	ERCOT
Seattle City Light	Agree	Puget Sound Energy
Colorado Springs Utilities	Agree	Snohomish County Public Utility District

1. **Transformer thermal impact assessment. The SDT has revised the Transformer Thermal Impact Assessmment white paper and Screening Criterion white paper with additional technical details. The screening criterion for transformer thermal assessments was increased from 15 A per phase to 75 A per phase. Additionally, look up tables provide a transformer thermal assessment approach based on available models. Do you agree with these changes? If not, please provide a specific recommendation and technical justification**

Summary Consideration: The SDT thanks all commenters. The following changes have been made:

- Rationale Box for Requirement R5 was revised to clearly indicate that a thermal assessment could be performed by using maximum effective GIC information from part 5.1 or GIC(t) from part 5.2.
- Clarifications and editorial changes to the Screening Criterion for Transformer Thermal Impact Assessment white paper. A parenthetical clarification was made on page 3 to indicate that the stated temperature refers to full load bulk oil temperature. Table numbering on page 8 was corrected. A mathematical error was corrected in the example on page 8.

Responses to all comments are provided below.

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Affiliates	No	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. Comments: 1. The R5 Rationale should be changed as shown below to make it clear that one can use a simplified approach (R5.1 inputs with Table 1 of the Transformer Thermal Impact Assessment Whitepaper) or R5.2 inputs and a detailed

Organization	Yes or No	Question 1 Comment
		analysis."The maximum effective GIC value provided in Part 5.1 can be used for transformer thermal impact assessment.""GIC(t) provided in Part 5.2 can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment." 2. The simplified, R5.1-based approach has not yet been made practical. R5.1 inputs will consist of just an Amps-per-phase value corresponding to the red peak at hour 45.3 in Fig. 3 of the Transformer Thermal Impact Assessment White Paper, and the associated metallic hot spot temperature in Table 1 of the White Paper matches the hr-45.3 blue peak. This temperature is sustained for only an extremely brief period, and therefore means very little in determining the loss of transformer life. This point was discussed at length in the 11/5/14 teleconference of the SDT, Dr. Marti (the leading expert in the field) and the NAGF Standards Review Team. The conclusion was that Table 1 in the White Paper should be expanded to include maximum 1-hour and 4 or 5-hour temperatures, to supplement the present peak-temperature information. Only then would equipment owners have a tool suitable for deciding whether or not mitigation measures are needed.

Response:

1. The SDT agrees and has revised the Rationale Box for Requirement R5 as follows:

<u>Rationale for Requirement R5</u>:
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

Organization	Yes or No	Question 1 Comment
The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. GIC(t) provided in Part 5.2 ~~is~~ can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-DisturbanceMitigation.aspx A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1. 2. The SDT has carefully considered this comment and the discussion from the NAGF SRT. The analysis of the benchmark GMD event and available thermal models indicate that the more limiting factor is in fact the metallic hot spot temperature during short-term emergency loading criteria. Metallic hot spot temperatures are associated with the generation of gasses, not insulation loss of life. Consequently, Table 1 in the Transformer Thermal Impact Assessment white paper is the more conservative approach and is not improved with the addition of longer-duration metallic hot spot temperatures.		
PacifiCorp	No	PacifiCorp has two areas of concern: (1) A continuing concern regarding assessment of impacts of harmonics; and (2) The change of the VRF for Requirement R2 from Medium to High. 1. Assessment of impacts of harmonics. PacifiCorp agrees with the comments of Bonneville Power Association, and shares their concern about assessing impacts of harmonics. BPA states: Table 1 of the standard under event column indicates that facilities removed as a result of protection system operation or misoperation due to harmonics during GMD event need to be modeled. There seems to be three options to perform the required assessment; 1. Performing harmonic studies to justify not taking the var devices outage analysis or 2. Replace all

Organization	Yes or No	Question 1 Comment
		mechanical relays with microprocessor relays that have the capability to block harmonics or 3. Remove all SVCs or shunt caps and perform the assessment. Option one is not practical for the transmission planner to perform harmonic analysis for the entire system due to lack of tools and expertise. Option two is an expensive solution for a one in a hundred year event. Utilities do not build for extreme contingencies such as one in ten probability event. Removing all reactive devices under option three defeats the purpose of installing these reactive devices in the first place. BPA suggests that this low probability extreme GMD event should be evaluated under normal system conditions not under system contingency events. PacifiCorp appreciates the drafting team's acknowledgement that the tools and capability to perform harmonics analysis are not in wide availability in the industry. PacifiCorp supports the suggestion of MidAmerican and the MRO NERC Standards Review Forum in the last comment period that "R4, GMD Vulnerability Assessment...not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later." 2. The VRF for Requirement R2 has been changed from Medium to High. This change is for consistency with the corresponding requirement in TPL-001-4, which was raised to High in response to FERC directive. PacifiCorp does not support changing the VRF from Medium to High. The planning requirement of TPL-001-4 is not analogous since it is planning that is consistently done by the industry. The industry does not have enough experience with GMD events and their impact on the BES to support a high VRF for this requirement.
Response:		

Organization	Yes or No	Question 1 Comment
1. The SDT has reviewed your comment and acknowledges the tools to perform detailed harmonics analysis are not in wide availability in the industry. However, replacement of all protective relays or outaging all relays in the power flow case are extreme reactions to the uncertainty associated with harmonics. The SDT believes that reasonable engineering judgment can be exercised to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis. Loss of reactive compensation that has a high likelihood of tripping due to harmonics is an event that must be evaluated as part of the GMD Vulnerability Assessment because it is a known risk from GMD. Supporting technical guidance is available in the NERC GMD TF GMD Planning Guide (section 4.2 and 4.3) and the 2012 Interim Report (section 6.4). 2. The change of the VRF from Medium to High is to provide consistency with the VRF for approved standard TPL-001-4 Requirement R1 which is being revised to comply with FERC directives. See NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.		
Volkmann Consulting, Inc	No	The SDT has not justified this dramatic of change in the threshold
Response: The justification for the change in the thermal assessment threshold is included in the Screening Criterion for Transformer Thermal Assessment whitepaper which is included on the GMD Standard page on the NERC website.		
JEA	Yes	We believe that this further supports the conclusion that GMD will not be a significant issue to the FRCC region and possible other regions and therefore those areas that have a high likely hood of not being affected should be exempted until there is harder evidence to support such action.
Response: The potential impacts of GIC are not limited to transformer hot spot heating but more importantly, to transformer var absorption, voltage stability and harmonics issues. The SDT does not have a technically supportable basis to propose an exemption from the requirements of the standard to any portion of the North American transmission system.		
Bonneville Power Administration	Yes	1. The Transformer Thermal Impact Assessment white paper's Background section states: Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems.

Organization	Yes or No	Question 1 Comment
		If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk. TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779. This is also stated as the Purpose/Industry Need on the project page. BPA suggests that the SDT align the stated purpose of the standard to the language of R7, to develop a Corrective Action Plan addressing how the performance requirements will be met. 2. BPA believes the table on page 8 of the Screening Criterion for Transformer Thermal Assessment should be labeled Table 2 as it is referenced in the preceding sentence.
Response: 1. The SDT believes the purpose section of TPL-007 is clear and appropriately worded to describe the reliability objective of the planning standard. 2. The SDT thanks the commenter for identifying the labeling error in the Screening Criterion for Transformer Thermal Assessment whitepaper. The table has been corrected.		
Pepco Holdings Inc.	Yes	The 75 amps per phase maybe too high and result in overheating for some transformers. The criteria could be 50 amps per phase for all transformers or variable depending upon the transformer design type. The following limits are proposed: For 3 - phase core form transformers with a 3 limb core: i. 30 - 50 Amps / phase for base current ii. 100 Amps / phase for short duration GIC pulses For transformers that have other than a 3 - phase, 3 - limb core:

Organization	Yes or No	Question 1 Comment
		i. 20 Amps / phase for base current. ii. 50 Amps / phase for short - duration GIC pulses
Response: The SDT has reviewed the comment and has based its determination of the threshold on analysis that is explained in the Screening Criterion for Transformer Thermal Assessment whitepaper. The suggested alternative thresholds cannot be implemented since they are presented without technical justification.		
Public Service Enterprise Group	Yes	While we agree with the changes, as they would appear to provide a more realistic basis for screening criteria for thermal assessment, we suggest some clarification discussion may be helpful for the paragraph at the top of page 3 of the Screening Criterion document, particularly related to the reference to bulk oil temperature of 80°C. In initial reading this appeared to perhaps be an 80°C temperature rise, applied with an ambient of 30°C to give the top oil temperature limit of 110°C seen in Table 1. On closer reading it appears it may be the actual bulk oil temperature for the full load rating in an example transformer in the thermal models. To clarify, a brief description referencing where the 80°C bulk oil temperature comes from would be helpful.
Response: The SDT has reviewed your comment and will revise the explanation of the reference to the bulk oil temperature of 80^{o}C, which is the bulk oil temperature for the full load rating, as follows: Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 104°C and 150°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 150°C falls well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).		

Organization	Yes or No	Question 1 Comment
Northeast Utilities	Yes	Clarification is needed on whether or not the 75 A per phase is referring to AC or DC currents. Should we divide the current measured/calculated in the neutral by 3 since there are 3 phases, or is this some sort of current injection from GIC on the transformer for phase A, B or C?
Response: The SDT has reviewed the comment and confirms that the 75 A is effective dc current per phase.		
Interested Parties on NERC Standard TPL-007-1	No	Group Comments on NERC Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events November 21, 2014 Draft standard TPL-007-1, “Transmission System Planned Performance for Geomagnetic Disturbance Events,” is not a science-based standard. Instead, the apparent purpose of standard TPL-007-1 is to achieve a preferred policy outcome of the North American Electric Reliability Corporation (NERC) and its electric utility members: avoidance of installation of hardware-based protection against solar storms. The draft standard achieves this apparent purpose through a series of scientific contrivances that are largely unsupported by real-world data. Potential casualties in the millions and economic losses in trillions of dollars from severe solar storms instead demand the most prudent science-based standard. A 2010 series of comprehensive technical reports, “Electromagnetic Pulse: Effects on the U.S. Power Grid” produced by Oak Ridge National Laboratory for the Federal Energy Regulatory Commission in joint sponsorship with the Department of Energy and the Department of Homeland Security found that a major geomagnetic storm “could interrupt power to as many as 130 million people in the United States alone, requiring several years to recover.”

Organization	Yes or No	Question 1 Comment
		A 2013 report produced by insurance company Lloyd's and Atmospheric and Environmental Research, "Solar Storm Risk to the North American Electric Grid," found that: "A Carrington-level, extreme geomagnetic storm is almost inevitable in the future. While the probability of an extreme storm occurring is relatively low at any given time, it is almost inevitable that one will occur eventually. Historical auroral records suggest a return period of 50 years for Quebec-level storms and 150 years for very extreme storms, such as the Carrington Event that occurred 154 years ago." "The total U.S. population at risk of extended power outage from a Carrington-level storm is between 20-40 million, with durations of 16 days to 1-2 years. The duration of outages will depend largely on the availability of spare replacement transformers. If new transformers need to be ordered, the lead-time is likely to be a minimum of five months. The total economic cost for such a scenario is estimated at $0.6-2.6 trillion USD." A 2014 paper published in the Space Weather Journal, "Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment" by C. J. Schrijver, R. Dobbins, W. Murtagh, and S.M. Petrinec found: "We find that claims rates are elevated on days with elevated geomagnetic activity by approximately 20% for the top 5%, and by about 10%for the top third of most active days ranked by daily maximum variability of the geomagnetic field." "The overall fraction of all insurance claims statistically associated with the effects of geomagnetic activity is 4%."

Organization	Yes or No	Question 1 Comment
		”We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude.” Given the extreme societal impact of a major solar storm and large projected economic losses, it is vital that any study by NERC in support of standard TPL-007 be of the highest scientific caliber and rigorously supported by real-world data. The unsigned white papers of the NERC Standard Drafting Team fail scientific scrutiny for the following reasons: 1. The NERC Standard Drafting Team contrived a “Benchmark Geomagnetic Disturbance (GMD) Event” that relies on data from Northern Europe during a short time period with no major solar storms instead of using observed magnetometer and Geomagnetically Induced Current (GIC) data from the United States and Canada over a longer time period with larger storms. This inapplicable and incomplete data is used to extrapolate the magnitude of the largest solar storm that might be expected in 100 years-the so-called “benchmark event.” The magnitude of the “benchmark event” was calculated using a scientifically unproven “hotspot” conjecture that averaged the expected storm magnitude downward by an apparent factor of 2-3. This downward averaging used data collected from a square area only 500 kilometers in width, despite expected impact of a severe solar storm over most of Canada and the United States. 2. The NERC Standard Drafting Team contrived a table of “Geomagnetic Field Scaling Factors” that adjust the “benchmark event” downward by significant mathematical factors dependent on geomagnetic latitude. For example, the downward adjustment is 0.5 for Toronto at 54 degrees geomagnetic latitude, 0.3 for New York City at 51 degrees geomagnetic latitude, and 0.2 for Dallas at 43 degrees geomagnetic latitude. These adjustment factors are presented in the

Organization	Yes or No	Question 1 Comment
		whitepaper in a manner that does not allow independent examination and validation. 3. The NERC Standard Drafting Team first contrived a limit of 15 amps of GIC for exemption of high voltage transformers from thermal impact assessment based on limited testing of a few transformers. When the draft standard failed to pass the second ballot, the NERC Standard Drafting Team contrived a new limit of 75 amps of GIC for exemption of transformers from thermal impact assessment, again based on limited testing of a few transformers. The most recent version of the "Screening Criterion for Transformer Thermal Impact Assessment" whitepaper uses measurements from limited tests of only three transformers to develop a model that purports to show all transformers could be exempt from the thermal impact assessment requirement. It is scientifically fallacious to extrapolate limited test results of idiosyncratic transformer designs to an installed base of transformers containing hundreds of diverse designs. The above described contrivances of the NERC Standard Drafting Team are unlikely to withstand comparison to real-world data from the United States and Canada. Some public GIC data exists for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper "Benchmark Geomagnetic Disturbance Event Description." Some public disclosures of transformer failures during and shortly after solar storms exist for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper "Screening Criterion for Transformer Thermal Impact Assessment." NERC is in possession of two transformer failure databases. This data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Screening Criterion for Transformer Thermal Impact

Organization	Yes or No	Question 1 Comment
		Assessment. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on transformer failures, contrary to Section 6.0 of the NERC Standards Processes Manual, “Processes for Conducting Field Tests and Collecting and Analyzing Data.” U.S. and Canadian electric utilities are in possession of GIC data from over 100 monitoring locations, including several decades of data from the EPRI SUNBURST system. This GIC data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Benchmark Geomagnetic Disturbance Event. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on measured GIC, contrary to Section 6.0 of the NERC Standards Processes Manual, “Processes for Conducting Field Tests and Collecting and Analyzing Data.” The NERC whitepaper “Benchmark Geomagnetic Disturbance Event Description” contains “Appendix II - Scaling the Benchmark GMD Event,” a system of formulas and tables to adjust the Benchmark GMD Event to local conditions for network impact modeling. Multiple comments have been submitted to the Standard Drafting Team showing that the NERC formulas and tables are inconsistent with real-world observations during solar storms within the United States. While the NERC Standard Processes Manual requires that the Standard Drafting Team “shall make an effort to resolve each objection that is related to the topic under review,” the Team has failed to explain why its methodology is inconsistent with measured real-world data. Even the most rudimentary comparison of measured GIC data to the NERC “Geomagnetic Field Scaling Factors” shows the methodology of “Appendix II-Scaling the Benchmark GMD Event” of whitepaper “Benchmark Geomagnetic

Organization	Yes or No	Question 1 Comment
		Disturbance Event Description” is flawed. For example, this comment submitted in standard-setting by Manitoba Hydro: “GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC’s of 24.5 Amps and 20.2 Amps.“ In the above instance, if the NERC “Geomagnetic Field Scaling Factors” were correct and all other factors were equal, the measured GIC amplitude at 45 degrees geomagnetic latitude should have been 1 Amp (5.3 Amps times scaling factor of 0.2). Were other GIC data to be made publicly available, it is exceedingly likely that the “Geomagnetic Field Scaling Factors” would be invalidated, except as statistical averages that do not account for extreme events. Notably, the above observation of Manitoba Hydro is consistent with the published finding of C. J. Schrijver, et. al. that “We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude.” The EPRI SUNBURST database of GIC data referenced in the above Manitoba Hydro comment should be made available for independent scientific study and should be used by the NERC Standard Drafting Team to correct its methodologies. American National Standards Institute (ANSI)-compliant standards are required by the NERC Standard Processes Manual. Because the sustainability of the Bulk

Organization	Yes or No	Question 1 Comment
		Power System is essential to protect and promptly restore operation of all other critical infrastructures, it is essential that NERC utilize all relevant safety and reliability-related data supporting assessments of geomagnetic disturbance impacts on “critical equipment” and benefits of hardware protective equipment. Other ANSI standards depend upon and appropriately utilize safety-related data on relationships between structural design or protective equipment and the effective mitigation of earthquakes, hurricanes, maritime accidents, airplane crashes, train derailments, and car crashes. Given the large loss of life and significant economic losses that could occur in the aftermath of a severe solar storm, and the scientific uncertainly around the magnitude of a 1-in-100 solar storm, the NERC Standard Drafting Team should have incorporated substantial safety factors in the standard requirements. However, the apparent safety factor for the “Benchmark GMD Event” appears to be only 1.4 (8 V/km geoelectric field used for assessments vs. 5.77 V/km estimated). The NERC Standard Processes Manual requires that the NERC Reliability Standards Staff shall coordinate a “quality review” of the proposed standard. Any competent quality review would have detected inconsistencies between the methodologies of the “Benchmark Geomagnetic Disturbance Event Description” and real world data submitted in comments to the Standard Drafting Team. Moreover, any competent quality review would have required that the Standard Drafting Team use real-world data from the United States and Canada, rather than Northern Europe, in developing the methodologies of the “Benchmark Geomagnetic Disturbance Event Description” and “Screening Criterion for Transformer Thermal Impact Assessment.”

Organization	Yes or No	Question 1 Comment
		Draft standard TPL-007-1 does not currently require GIC monitoring of all high voltage transformers nor recording of failures during and after solar storms. These requirements should be added given the still-developing scientific understanding of geomagnetic disturbance phenomena and its impact on high voltage transformers and other critical equipment. Going forward, data on observed GIC and transformer failures during solar storms should be publicly released for continuing scientific study. NERC can and should substitute a science-based standard to model the benefits and impacts on grid reliability of protective hardware to prevent long-term blackouts due to solar geomagnetic storms. Submitted by: Thomas S. Popik Chairman Foundation for Resilient Societies William R. Harris International Lawyer Secretary, Foundation for Resilient Societies Dr. George H. Baker Professor Emeritus, James Madison University Director, Foundation for Resilient Societies Representative Andrea Boland Maine State Legislature

Organization	Yes or No	Question 1 Comment
		Sanford, ME (D) Dr. William R. Graham Chair of Congressional EMP Commission and former Assistant to the President for Science and Technology Director, Foundation for Resilient Societies William H. Joyce Chairman and CEO Advanced Fusion Systems John G. Kappenman Owner and Principal Consultant Storm Analysis Consultants, Inc.
Response: The SDT thanks the contributors for participating in the standards development process and for the detailed comments. 1. Observational data for years 1993-2013 were used in the generation of the geoelectric field statistics. This is an extensive data set that covers almost two solar cycles and includes major storms such as the famous Halloween storm of October 2003. It is important to note that the averaging process does not assume the existence of ionospheric hotspots. The geoelectric field is characterized in regional scales without making any assumptions about the actual field structure. Localized hotspots, if they exist, will be reduced in amplitude in the averaging process as we are interested in regional-scale rather than point wise enhancements in the field. Large-scale spatially coherent enhancements are not reduced in amplitude in the averaging process. 2. The geomagnetic latitude scaling factor is based on results presented in peer-reviewed scientific literature (Pulkkinen et al., 2012; Ngwira et al., 2013; Thomson et al., 2011). The results are based on publicly available data from worldwide distribution of geomagnetic observatories. Consequently, all necessary data are available for independent examination and validation of the results.		

Organization	Yes or No	Question 1 Comment
3. The SDT revised the thermal screening criterion from 15 A per phase to 75 A per phase after conducting extensive simulation of the benchmark GMD event on the most conservative thermal models known to date. The revision was also based on input from transformer manufacturer and industry SMEs. The justification is documented in the thermal screening criterion white paper. References: Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, Space Weather, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012. Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, Space Weather, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013. Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, Space Weather, 9, S10001, doi:10.1029/2011SW000696, 2011.		
SmartSenseCom, Inc.	No	See Comment below at Section 1(b). SMARTSENSECOM, INC. COMMENTS ON PROPOSED STANDARD TPL-007-1 In recognition of the potentially severe, wide-spread impact of GMDs on the reliable operation of the Bulk-Power System, FERC directed NERC in Order No. 779 to develop and submit for approval proposed Reliability Standards that address the impact of GMDs on the reliable operation of the Bulk-Power System. In this, the second stage of that standards-setting effort, the Commission directed NERC to create standards that provide comprehensive protections to the Bulk-Power System by requiring applicable entities to protect their facilities against a benchmark GMD event.

Organization	Yes or No	Question 1 Comment
		In particular, FERC directed NERC to require owners and operators to develop and implement a plan to protect the reliability of the Bulk-Power System, with strategies for protecting against the potential impact of a GMD based on the age, condition, technical specifications, or location of specific equipment, and include means such as automatic current blocking or the isolation of equipment that is not cost effective to retrofit. Moreover, FERC identified certain issues that it expected NERC to consider and explain how the standards addressed those issues. See Order No. 779 at Â¶ 4. Among the issues identified by FERC was Order No. 779's finding that GMDs can cause "half-cycle saturation" of high-voltage Bulk-Power System transformers, which can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. FERC also found that half-cycle saturation from GICs may severely damage Bulk-Power System transformers. While the proposed standard addresses and explains transformer heating and damage with a model, NERC ignores the issues of harmonic generation and reactive power consumption caused by a GMD event that have caused grid collapse in the past. FERC has also been very clear to NERC that it considered the "collection, dissemination, and use of GIC monitoring data" to be a critical component of these Second Stage GMD Reliability Standards "because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models." See Order No. 797-A, 149 FERC Â¶ 61,027 at Â¶27. However, the proposed standard fails to tie the actions required under the standard to any actual grid conditions. In its place, the proposed standard relies entirely upon an untested system model with several suspect inputs and with no means for model verification and no affirmative requirement for real-time monitoring data as a means to enable GMD mitigation.

Organization	Yes or No	Question 1 Comment
		It has been nearly eighteen months since Order No. 779 and this comment cycle represents NERC's last opportunity to correct its course before it files TPL-007-1 with FERC. Based on the considerable volume of scientific evidence and the capabilities of modern measurement and control technology to serve as a mitigation method, the proposed standard is technically unsound and fails to adequately address FERC's directives. Rather than risk the operation of the grid on the perfection of an untested model, NERC should have provided requirements for the collection and dissemination of GMD information, such as data collected from real-time current and harmonic monitoring equipment, to ensure that the Bulk-Power System is able to ride-through system disturbances. NERC should include these measures inTPL-007-1 or be prepared for a likely FERC remand - leaving the Bulk-Power System exposed to the risk of GMD while NERC addresses the matters that it ought to have considered at this stage of the process. 1. TPL-007-1 Should be Modified to Account for the Impact of System Harmonics and VAR Consumption and Mitigate the Risk Created by Reliance On Untested System ModelsIn Order No. 779, FERC found that GMDs cause half-cycle saturation of Bulk-Power System transformers, which can lead to transformer damage, increased consumption of reactive power, and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. Whereas TPL-007-1 takes pains to model transformer thermal heating effects, the proposed standard does not adequately address the risks posed by harmonic injection and VAR consumption. Failure to deal directly with the effects of harmonics and VAR consumption is irresponsible given the empirical evidence of their impact upon system reliability during GMD events. Real-time monitoring, as called for by FERC, would provide the real-time operating information necessary to account for - and mitigate - these negative system effects. Real-time

Organization	Yes or No	Question 1 Comment
		monitoring information would also remedy the vulnerability created by standard's "model-only" approach to the GMD threat and provide a means to iteratively improve any model over time. A. Failure to Account for Harmonics and VAR Consumption. In the presence of a GIC, a saturated transformer becomes a reactive energy sink, acting as an unexpected inductive load on the system, and behaves more like a shunt reactor. Consequently, transformer differential protective relays may trip and remove the transformer from service because of the disproportionately large primary current being drawn and consumed by the saturated transformer. System VAR support devices, such as capacitor banks and SVCs, become particularly critical during such conditions in order to offset the undesired behavior of GIC-affected transformers. The magnetizing current pulse of a GIC-inflicted transformer injects substantial harmonics into the power system. VAR support devices are a low impedance path for harmonic currents and subsequently these devices begin to draw large currents too. A power flow "tug-of-war" ensues between the saturated transformers and VAR support devices. The sustenance of the VAR support devices is paramount as their failure may result in system voltage instability and collapse. However, harmonics doom these devices on multiple counts. For example, the large harmonic currents being consumed by capacitor banks may affect other components in the device that cannot withstand such high magnitude currents and result in damage and the unwanted tripping of the capacitor bank. Additionally, harmonics often result in the improper operation of protective equipment, such as overcurrent relays. Therefore, harmonics are ultimately predisposing system VAR support components to failure and increasing the vulnerability of the grid to voltage instability and collapse. See Duplessis, The Use of Intensity Modulated Optical

Organization	Yes or No	Question 1 Comment
		Sensing Technology to Identify and Measure Impacts of GIC on the Power System (attached). Accounting for GIC-related harmonic impacts is also essential considering that where GICs have caused significant power outages, harmonics have been identified as the primary system failure mode through the improper tripping of protection relays in known GMD events. For example, the 1989 Quebec blackout was traced to improper protective device tripping influenced by the GIC-induced where seven large static VAR compensators were improperly tripped offline by relays. See Department of Homeland Security, Impacts of Severe Space Weather on the Electric Grid, Section 4.4. In light of FERC's directive to address and explain how the standard address these issues, it is clear that TPL-007-1 be modified to directly account for the reactive power and harmonic effects of GMD events. B. Over-Reliance on Untested Models. The core of the proposed standard is a series of models designed to approximate the "worst-case" scenarios of a GMD event which are, in turn, used to determine system vulnerability and whether corrective action is required. This "model-only" approach is technically insufficient and leaves the grid open to unnecessary risk. Moreover, no mechanism exists in the standards to validate the GMD models through the use of actual operating data. First, genuine concerns exist regarding whether the "worst-case" GMD scenario is actually being modeled or whether the model substantially underrepresents the threat. For example, according to empirically-based arguments of John Kappenman and William Radasky in their White Paper submitted to the NERC earlier this year, the NERC Benchmark model underestimates the resulting electric fields by factors of 2x to 5x. Kappenman et al., Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in

Organization	Yes or No	Question 1 Comment
		this NERC GMD Standard. The thermal heating model also relies upon a 75 amps per phase assumption (equivalent to total neutral GIC of 225 amps) as the modeled parameter. As shown in the Oak Ridge Study, it was found that at as little as 90 amps (or 30 amps per phase) there is risk of permanent transformer damage. See, e.g., Oak Ridge National Laboratory, FERC EMP GIC Metatech Report 319 at 4-8 ("Oak Ridge Study"). Indeed, the Oak Ridge Study found that a 30 amps per phase level is the approximate GIC withstand threshold for the Salem nuclear plant GSU transformer and possibly for others of similar less robust design in the legacy population of U.S. EHV transformers. See Oak Ridge Study at Table 4-1 (finding 53% of the Nation's 345kV transformers at risk of permanent damage at a 30 amps per phase GIC level). In addition, the system model specified in Requirement 2 should also be run on the assumption that all VAR support components on the system (e.g., capacitor banks, SVCs, etc.) become inactive (i.e., removed from service by undesired operation of protective devices caused by the harmonics that GIC affected transformers are injecting into the system). That the models appear to substantially under-estimate the expected GMD impact is critical as it the models alone - under the proposed standard - that drive the vulnerability assessments and corrective action plans that require owners and operators to implement appropriate strategies. As written, these models have the effect of greatly reducing the scope of the protective requirements that will be implemented, potentially allowing sizable portions of the grid to be wholly unprotected and subject to cascading blackouts despite the adoption of standards. The extensive analysis and findings of the Kappenman-Radasky White Paper and the Oak Ridge Study suggest that the modeling approach elected by NERC is technically unsound, does not accurately assess a "worst case" scenario

Organization	Yes or No	Question 1 Comment
		as it purports to do, and, in any event, should not be the sole basis for the standard's applicability. Second, the proposed standard provides no means to validate or update the standard's models in light of actual operating data. This amounts to little more than a gambler's wager that the model will adequately protect the Bulk-Power System from a substantial GMD event, when it has never actually been tested. As the model is designed, actual operating data has no means to influence or override actions based upon the model. This is inappropriate. As discussed above, it is likely that the model developed will underestimate the effects of a GMD event. To rely on a model to simulate actual equipment performance over a range of potential GMD disturbances, it is essential that that model must not only contain adequate information (i.e. - an accurate up-front estimate), but that it must also correspond to actual reported field values. NERC should modify the standard to provide that actual operating data be used to regularly verify and improve the model. C. The Solution - Collect, Disseminate, and Use Real-Time Reactive Power and Harmonic Content Information to Mitigate GMD Impacts. While the standard's model-based approach to GMD mitigation efforts may have some limited utility as a first step towards identifying vulnerabilities and developing forward-looking correction action plans, the standard would provide far better protection with a requirement for the collection and use of accurate, real-time data regarding current, reactive power consumption, and system harmonics. Real-time data should underpin any GMD mitigation efforts, substantially reducing the risk of outages and damage to critical equipment in the event of a GMD, and would also improve the reliability of system models. Modern grid measurement and control technologies are capable and readily deployable to mitigate GMD events.

Organization	Yes or No	Question 1 Comment
		First, real-time monitoring enables protective devices to be efficiently managed during a GIC event, initiating control signals that enable devices to “ride-through” GMD where they may otherwise trip offline during a period of normal operation. In these instances, the detection of harmonic content could be used to sense transformer saturation and override normal protective device trip settings in order to maintain key equipment online and not be “fooled” into tripping by the harmonics generated by the event. Given the diversity of protective devices for equipment used throughout the Bulk-Power System, a technically preferable approach would be to actively manage protection schemes based upon real-time operating data. Regarding the system’s VAR response, if system voltage becomes unstable when VAR support is inhibited during a GIC event, operators would have an available solution through the identification of atypical harmonics, which can be associated with a GIC event, and this information used as a trigger to implement alternate protective schemes for VAR support components for the duration of the GIC event. Second, if a GMD event is detected through the monitoring of systemic VAR consumption and harmonic content at key points in the network (which may include current monitoring on vulnerable transformer neutrals and monitoring of harmonics and VAR consumption on phases), this real-time monitoring data could be used to draw down, and ultimately cease, GMD operating procedures as the GMD event passes. Moreover, the VAR and harmonic derived from real-time operation information may also be used to trigger operating procedures, which is necessary given that the existing operational standard relies on space weather forecasts as the trigger for the implementation of operating procedures, despite the substantial error rates associated with these forecasts. Since GMD procedures impose transmission constraints that do not permit wholesale energy markets or system dispatch to achieve the most efficient use of available

Organization	Yes or No	Question 1 Comment
		resources, ultimately affecting the prices paid by consumers, NERC should seek to minimize the frequency and duration of mitigation efforts. Real-time monitoring of harmonic content and reactive power would enable a more efficient approach to recognizing and reacting to GMD events, harmonizing the Phase I and Phase II standards and providing greater overall protection to the grid. Further, real-time monitoring information must be used to validate models that are used to inform the means by which owners and operators will prepare for, and react to, GMD events. Currently, the models presented in the standard are the sole means to trigger the implementation of protection measures and the availability of actual operating data that questions the model's outputs have no means to override the model-based approach. The use of actual operating data to verify the standard's model would improve the accuracy of model verifications needed to support reliability. A better approach would be to use modeling and real-time monitoring in tandem to constantly verify and enhance the model, while still maintaining protections for "missed" events that the model is likely to inevitably overlook. The people of the United States should not have the ongoing Bulk-Power System reliability put at risk by an unverified model. NERC should use its authority to insure that real operating data will, over time, be employed to verify and improve any reference model and that real operating data will be employed as a means to ensure ongoing system reliability when events render the reference model unequal to its protective task (which evidence suggests will happen). The proposed standard should be modified to require the collection, dissemination, and use of real-time voltage and current monitoring data which will provide the reactive power and harmonic content information necessary to effectively and efficiently manage the system in response to GMDs.

Organization	Yes or No	Question 1 Comment
		2. Conclusion. FERC was clear in its direction to NERC that the collection, dissemination, and use of real-time GIC monitoring data was a critical component of these Second Stage GMD Reliability Standards “because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models.” See Order No. 797-A, 149 FERC Â¶ 61,027 at Â¶ 27. FERC also was clear that harmonic content and reactive power consumption created by GMD events constituted serious threats to system reliability that must be addressed. Order No. 779 at Â¶ 7.The draft standard offered by NERC simply fails to meet the needs identified by FERC - which are amply supported by the record established in these proceedings - a reasonable person could reach no other conclusion. To create a reasonable and prudent standard, NERC needs to address the reactive power and harmonic generation aspects of GMD events, and it needs to provide for verification and improvement of the model included in the draft standard. The only route to meeting those needs that is supported by the evidentiary based findings and FERC’s directives is a mandate for the collection, dissemination, and use of real-time GIC current and harmonic data to drive protection schemes. With clearly articulated requirements for such data, NERC can fill the gaps in the current standard and provide a means by which to adequately protect the Bulk-Power system. Respectfully submitted,/s/Christopher J. Vizas Aaron M. Gregory SMARTSENSECOM, INC. cvizas@smartsensecom.com agregory@smartsensecom.com Date: November 21, 2014

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks the commenter for participating in the standards development process. The following response is provided: 1. TPL-007 addresses impacts from GMD-related harmonics and var consumption. The proposed standard requires planning entities to conduct a GMD Vulnerability Assessment that includes steady state power flow analysis and supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Table 1 further defines the planning event to include "Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event". 2. The SDT agrees that monitoring is a valuable component for many mitigation approaches and will further enhance system level understanding of GMD impacts. Monitoring is addressed in technical supporting material including the GMD Planning Guide and the 2012 GMD Report. 3. The benchmark GMD event has been technically justified in the supporting white paper. Assertions that plane wave methods systematically underestimate geoelectric field calculations are technically unsubstantiated. Earth impedance models published by the USGS have an element of uncertainty (as they may result in either overestimation or underestimation of geoelectric fields), and the SDT agrees that they should be updated as necessary with the use of good quality geomagnetic field and GIC measurements made at consistent data acquisition rates. 4. The standard addresses the risk of widespread transformer damage and uncontrolled cascading wide area blackouts. The standard is not intended to address the performance of individual transformers with known design deficiencies or in poor operating conditions. 5. The SDT agrees with the commenters' examples of use of real-time monitoring and effective operating procedures. The comments are consistent with technical references such as the GMD Planning Guide. Other approaches may be equally or more effective in addressing impacts identified in GMD Vulnerability Assessments. Consequently, the proposed standard should provide responsible entities with flexibility to meet specified performance criteria and not prescribe specific approaches.		

Organization	Yes or No	Question 1 Comment
6. The SDT agrees that the benchmark GMD event and earth impedance models should be periodically reviewed and updated with additional information and data; this can be accomplished outside of the reliability standard using a process such as the periodic review of standards that is required under NERC Rules of Procedure.		
John Kappenman, Storm Analysis Consultants		Regarding NERC Draft Standard on Transformer Thermal Impact Assessments (comment appended to end of this report)
Response: A central point made in the comments is that delta winding heating due to harmonics has not been adequately considered by the SDT and that thermally this is a bigger concern than metallic part hot spot heating. Comments pertaining to tertiary winding harmonic heating are based on the assumption that delta winding currents can be calculated using the turns ratio between primary and tertiary winding. This assumption is incorrect when a transformer is under saturation. Therefore, the concerns regarding delta windings being a limiting problem from a thermal point of view are unwarranted. The criteria developed by the SDT uses state-of-the-art analysis methods and measurement-supported transformer models.		
SERC PSS Ameren	Yes	We appreciate the standard drafting team's efforts at reducing the potential scope of transformers needing to be evaluated, as well as streamlining the evaluation process.
ACES Standards Collaborators	Yes	We would like to thank the SDT for reviewing the screening criterion for transformer thermal assessments and increasing it to 75 A per phase or greater.
Colorado Springs Utilities	Yes	CSU agrees that this is a trend in the right direction. Thank you for all of your efforts in evaluating this threshold!
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration L.P. (ICLP) finds that both the transformer screening criterion and look-up tables are welcome updates to the GMD initiative. In our view, they reflect the best available knowledge surrounding the impact of geomagnetically induced currents on susceptible BES transformers. We

Organization	Yes or No	Question 1 Comment
		recognize that some stakeholders prefer a far more conservative approach to GMD-resiliency, but the experience with the phenomena over the last several decades does not justify the costs. That may change as our familiarity with GMD grows over time, but for now, these dollars are best spent on more pressing reliability issues.
Manitoba Hydro	Yes	The drafting team has greatly improved the standard by moving the threshold from 15A to 75A per phase. The screening criterion included in Table 1 (of the Screening Criterion for Transformer Thermal Assessment) makes it very easy to determine whether the metallic hot spot temperature of 200C is exceeded.
California ISO	Yes	The California ISO supports the comments of the Standards Review Committee.
American Electric Power	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Texas Reliability Entity, Inc	Yes	
Bureau of Reclamation	Yes	
Seattle City Light	Yes	
Oncor Electric Delivery LLC	Yes	

Organization	Yes or No	Question 1 Comment
South Carolina Electric & Gas	Yes	
Exelon and its Affiliates	Yes	
American Transmission Company	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Iberdrola USA	Yes	
Northeast Power Coordinating Council	Yes	
Con Edison, Inc.	Yes	
MRO NERC Standards Review Forum	Yes	
OG&E	Yes	
Duke Energy	Yes	
LCRA Transmission Services Corporation	Yes	

Organization	Yes or No	Question 1 Comment
David Kiguel	Yes	
Puget Sound Energy, Inc.	Yes	
Avista Utilities	Yes	
Tacoma Power	Yes	
Idaho Power Company	Yes	
DTE Electric		No Comment

2. TPL-007-1. Do you agree with the changes made to TPL-007-1? If not, please provide technical justification for your disagreement and suggested language changes

Summary Consideration: The SDT thanks all commenters. The following changes have been made to the proposed standard:

- Corrected VRF terminology in Requirement R1.
- Added technical guidance to the applications guidelines section for Requirement R2 to address underground pipe-type transmission cable.
- Revised the rationale box for Requirement R7 to more clearly indicate necessary considerations in developing a Corrective Action Plan.
- Revised R6 to clarify that the 24-month timeline for R6 is based on receipt of GIC information provided in Requirement R5 part 5.1. R6 now states:

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5 Part 5.1 is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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 Part 5.1.

Response to specific comments follows.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	1. The Standard Drafting Team responded to our concerns on the omission of modeling for shielded, underground pipe-type transmission lines in the last posting with the following (posted in the Consideration of Comments): ”The SDT agrees that underground pipe-type cables should not be modeled as GIC sources. GIC, induced in the pipe, will circulate through the pipe, cathodic protection and ground return circuit, but it is probably an order of magnitude lower than what be induced in an unshielded transmission circuit. However, the cables will carry GIC induced elsewhere (overhead circuits) and must be included in the dc network (but not as dc sources) as well as the load flow base case. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.” Current modeling methods associate the driving force of GICs to impact all transmission lines according to location and length, but not with regard to their status as underground or overhead. However, the ability of GMDs to induce currents in underground lines is highly questionable, as their surrounding pipe type structures would be expected to act as a Faraday Cage, completely isolating the cables from a GMD event. It is expected that the overall GIC response for an underground pipe-type cable system would be significantly reduced in comparison to its overhead counterpart. There is no method currently available to create this model or differentiate underground shielded lines with contributions of zero or severely attenuated magnitudes of GIC. Therefore, the current modeling software cannot be used to gauge the impact of GMDs, and the true extent and impact of GMDs cannot be accurately assessed. The Drafting Team should consider excluding underground pipe-type cable from the standard. Referring this issue to the NERC technical committees is not sufficient. The technical committees may not implement the suggestion that all underground pipe-type cables are zero GIC sources. This suggestion has also not been implemented by the GIC modeling application developer(s).

		2. Additionally, it has been raised on previous postings that the GMD Benchmark is much more severe than what has been observed in Hydro-Quebec's historical record. The parameters behind Attachment 1 and Table 1 are not adequately justified. A preliminary evaluation that applied the GMD Event Benchmark of 4 to 8 V/km on Hydro-Quebec's System necessitates unjustified investment to satisfy extraordinary system conditions that have never been experienced. The GMD Benchmark gets a maximum value of 8 V/km for the 60 degree geomagnetic latitude, above which the value is constant. We would like to propose the SDT to apply the constant value to a lower geomagnetic latitude. This would allow for a constant value of E (V/km) for all Quebec and Canada but lower than in the actual Benchmark without affecting most United States entities. This proposal would respect the actual standard's structure and provide a more realistic value.

Response:

1. Thank you for your comment and amplifying information. The SDT maintains that underground pipe-type transmission lines are a necessary component of the dc network and therefore cannot be excluded from the proposed standard. The following has been added to the guidelines and technical basis section for R2:

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Commercially available modeling software allows setting the induced geoelectric field on any transmission circuit to a user-defined value (near zero in this case).

2. The SDT maintains that the 100-year benchmark is an appropriate reference storm for GMD Vulnerability Assessments due the potential for wide area impacts from GMD events. It is recognized that the benchmark GMD event is of greater magnitude that historically recorded storms such as the March 1989 event.

Con Edison, Inc.	No	The Standard Drafting Team responded to concerns on the omission of modeling for shielded, underground pipe-type transmission lines with the following: ”The SDT agrees that underground pipe-type cables should not be modeled as GIC sources. GIC, induced in the pipe, will circulate through the pipe, cathodic protection and ground return circuit, but it is probably an order of magnitude lower than what be induced in an unshielded transmission circuit. However, the cables will carry GIC induced elsewhere (overhead circuits) and must be included in the dc network (but not as dc sources) as well as the load flow base case. The SDT will refer that issue to NERC technical committees with the suggestion to address this modeling issue in future revision of the GMD Planning Guide.” Referring this issue to the NERC technical committees is not sufficient; the technical committees may not implement the suggestion that all underground pipe-type cables are zero GIC sources. This suggestion has also not been implemented by the GIC modeling application developer(s). The ability of GMDs to induce currents in underground lines is highly questionable, as their surrounding pipe-type structures would be expected to act as a Faraday cage, completely isolating the cables from a GMD event. In view of the impact that this enhancement would have on the evaluation of GIC currents in portions of the NPCC region, we request that the issue be captured in Attachment 1 or in the Application Guideline associated with TPL-007-1.
Response: Thank you for your comment and amplifying information. The SDT added the following to the guidelines and technical basis section for R2: Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.		

MRO NERC Standards Review Forum	No	1. Page 11, Table 1 -Steady State Planning Events. The NSRF suggest that the SDT provide a tool or guidance on the method of determining Reactive Power compensation devices and other Transmission Facilities that are removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event. If a tool cannot be provided in a timely fashion. We suggest language be added to the implementation plan that provides R4, GMD Vulnerability Assessment, will not be implemented until after guidance for the industry is readily available or the date provided in the implementation plan whichever is later. The Planning Application Guide's Sections 4.2 and 4.3 specifically mention the unavailability of tools and difficulty in performing an accurate harmonic assessment but does not provide resolution or recommendation on how to accurately address the concern. The statement from Section 4-3 is referenced below. "The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results." Additionally, there needs to be a clearer definition of how the steady state planning analysis due to GMD event harmonics is to be performed. Is it the intent of the standard to study the removal of all impacted Transmission Facilities and Reactive Power compensation devices simultaneously, sequentially, or individually as a result of Protection operation or Misoperation due to harmonics? 2. The Planning Application Guide references the "NERC Transformer Modeling Guide" in several places as a reference for more information on how to perform the study. The "NERC Transformer Modeling Guide" is shown in the citations as still forthcoming. Further, The NSRF does not believe it is feasible to implement a

		full harmonic analysis in the implementation timeframe for TPL-007. In a very broad view, the standard requires a specific analysis that the industry doesn't have the skill set or tools to perform. This is acknowledged by the supporting documents. The reference document cited as a resource to further explain how to perform the studies has not been created yet. 3. Page 20, Table of Compliance Elements - VRF for R2. The NSRF does not agree with the change to the VRF for R2 from "Medium" to "High". The VRF of "High" for R2 is not in line with the NERC VRF writing guide.
Response: 1. The SDT has reviewed your comment and acknowledges the tools to perform detailed harmonics analysis are not in wide availability in the industry. However, the SDT believes that reasonable engineering judgment can be exercised to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis. As written, the standard provides flexibility for planners to apply engineering judgment and is appropriately supported by technical resources including the NERC GMD TF GMD Planning Guide (section 4.2 and 4.3) and the 2012 Interim Report (section 6.4). A prescriptive tool or method as suggested by the commenter would not be effective in application to all planning entities. Furthermore, the SDT does not support making implementation of Requirement R4 contingent upon development of a prescriptive tool for GMD harmonics analysis. 2. While the NERC GMD TF continues to develop a Transformer Modeling Guide which is expected to be available in 2015, there are sufficient technical resources available now to conduct a GMD Vulnerability Assessment. 3. The change of the VRF from Medium to High conforms to FERC and NERC guidelines requiring consistency among Reliability Standards (see guideline 3 in the VRF/VSL justification posted on the project page). TPL-001-4 Requirement R1 is an analogous requirement which is being revised from Medium to High to comply with FERC directives. See NERC filing dated August 29, 2014 (RM12-1-000).		
Associated Electric Cooperative, Inc.	No	1. Transformer Modeling Guide - An acceptable implementation time cannot be accurately determined or agreed upon without the availability or experience with

		resources that are mandatory with currently drafted requirements. AECI respectfully requests one of the following. (a)Modify the implementation plan to specifically state that transformer thermal assessment time requirements are dependent on the availability of a technically sound modeling guide, -or- (b) include exception within the deadline that considers an inability to attain necessary tools or resources to complete this portion of the study, -or- (c) provide technically reasoned response on why the SDT disagrees with this approach. 2. DC Model Coordination - The current implementation plan does not consider the logistical steps inherent in model coordination and the compliance risk associated with failing to determine specific deadlines for both internal and external models. This concern cannot be mitigated during the planning coordinator phase when considering that the issue exists between two planning coordinator areas. AECI respectfully requests: Modify the implementation plan for DC model coordination to include a deadline for internal model development, and additional time for external model development through coordination with neighbors. The end result could be the exact same amount of time allotted for this phase, but with a staggered approach to promote good modeling practices between entities. 3. Contingency Mitigation Using Load Shed - AECI appreciates the SDT responsiveness to prior comment concerning the use of load shed as a mitigation to meet BES performance. However, the current language lacks clarity regarding the minimization of Load Loss or Firm Transmission Service. AECI respectfully requests the following. Modify Table 1, Steady State Performance Footnotes - Please clarify “The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.” How should a transmission planner

		apply this language in the development of MW thresholds used to determine the validity of a mitigation option?
Response: 1. Technical resources necessary to perform the thermal impact assessment are available. Consequently, the SDT does not agree with the commenter's suggestion to modify TPL-007 or the Implementation Plan. The technical justification is provided in the thermal impact assessment white paper posted on the project page. 2. With respect to the issue of dc Model coordination, the SDT believes the addition of a specific milestone to the implementation plan for model coordination would add complexity and is not the most efficient approach to accomplish the objective. The preferred approach is to leave the sequencing of the development of the respective internal and external models in the hands of the planning entities. 3. Similarly, regarding the request for more specificity on the limits of acceptable load loss or firm service curtailment, the SDT's intent is to provide flexibility for planning entities to determine acceptable thresholds for load loss, if any, based on system and planning considerations. The commenter recommended modifying Table 1 footnotes; a suggested change was not provided for consideration.		
PPL NERC Registered Affiliates	No	R7 gives the Responsible Entity determined by the PC/TP the sole authority to develop a Corrective Action Program (CAP) that may include, "Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment." There is no provision for the equipment owner to have the opportunity to demonstrate there may be a better, more cost-effective system to remedy the problem. The SDT stated in the 11/5/14 teleconference with the NAGF SRT that these are not excessive powers, since they involve only making a plan, not an implementation order. The NERC Glossary definition of a CAP, however, is, "A list of actions and an associated timetable for implementation [emphasis added] to remedy a specific problem." The statements, "will be met," in R7 and, "actions needed," in R7.1 make it additionally clear that TPL-007-1 CAPs aren't just discussion-starting lists of

		possibilities; they do in fact constitute implementation orders. Giving the Responsible Entity such sweeping powers over equipment owned by others is particularly problematic for GOs in a deregulated market where the GO may never be able to recover the cost (potentially millions of dollars) of the modified, retired or removed equipment. Moreover, the standard should provide the recipient of a Corrective Action Plan that continues to disagree with the Responsible Entity's decision with recourse to challenge the determination. To that end, we suggest that a subsection 7.3.2 be added providing that, "If disagreement between the recipient of the Corrective Action Plan and the Responsible Entity continues after the foregoing process, the recipient may seek resolution of the dispute by NERC and/or FERC."
Response: The SDT disagrees with the comment that the planning entities have sole authority to develop a Corrective Action Plan. The development of a Corrective Action Plan is generally done via a collaborative process with the asset owners or in consultation with internal customers for vertically integrated entities. The SDT did not intend to establish requirements for the implementation of the Corrective Action Plan in this standard because the implementation would be addressed in processes that are outside of the standards process.		
ACES Standards Collaborators	No	1. We recommend that the SDT remove all references to the TP and require the PC to be the responsible entity. 2. We continue to have concerns that the applicability section includes transformers that may not be a part of the BES. This standard should apply only to BES Facilities. 3. We have concerns with the increased violation risk factor for Requirement R2 from medium to high. We disagree that a requirement for the maintenance of system models should be classified as a high VRF. Requirement R2 is lacking a specific timeframe on how often these models must be maintained. Moreover, the lack of maintaining a model will not result in a cascading, separation, or instability event. We recommend moving the VRF back to medium, because it is

		an administrative task that should not result in monetary penalties up to $1 million per violation. (4) Thank you for the opportunity to comment.
Response: 1. The SDT considered refinement of the applicable entities in the standard but determined that the variation in the relationships between PCs and TPs in the North American systems prevented a single construct for applying the standard. 2. With regard to the issue of non-BES transformers, the SDT believes that exclusion of some non-BES transformers will provide incorrect results in the Benchmark GMD Vulnerability Assessment. Therefore, the SDT has set the equipment applicability to help ensure that accurate results are maintained. 3. The change of the VRF from Medium to High is to provide consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.		
DTE Electric	No	This draft Standard does not address in any detail the coordination and installation of any necessary mitigation measures (such as GIC reduction devices) once vulnerable transformers are identified. The Planning Coordinator/Transmission Planner would seem to be the entities best suited to determine where and what mitigation measures are put in place. R6.3 requires the transformer owner to describe mitigation actions, but the PC/TP would be better equipped to study and specify area mitigation strategies in cooperation with the transformer owners.
Response: The development of a Corrective Action Plan is generally done via a collaborative process with the asset owners or in consultation with internal customers for vertically integrated entities. The SDT believes Requirement R7 Part 7.3 and R6 Part 6.4 provide for the information exchange needed for this coordination.		

SmartSenseCom, Inc.	No	See below White Paper in support of Comment Submitted. PDF submitted separately. The Use of Intensity Modulated Optical Sensing Technology to Identify and Measure Impacts of GIC on the Power System. Jill Duplessis, SmartSenseCom, Inc., Washington, D.C. jduplessis@smartsensecom.com U.S.A. Abstract: This paper describes the phenomenon of geomagnetically induced currents ("GIC"), a geomagnetic disturbance's potential impact on transformers and the electric power system, and FERC/NERC regulation regarding utility responsibility. The paper then introduces intensity modulated optical sensing technology, explains how this technology has been adapted to measure voltage, current, phase and other characteristics of electric phenomena, and answers why this adaptable core technology provides a comprehensive solution to identifying and measuring the impacts of GIC.
Response: The SDT recognizes this is submitted in support of SmartSenseCom's comments in Q1 and has responded accordingly.		
Colorado Springs Utilities	No	Thank you for all of your efforts and your comments. We know that this is a very complex issue that unfortunately receives excessive political publicity. We really appreciate the SDT's efforts. The following are some the SDT's comments in response to some feedback we provided during the last posting. "Field tests are governed by Section 6 of the Standards Process Manual (SPM). As described, these programs are conducted prior to formal comment periods to inform the standard development effort. SDT members have collectively conducted multiple GMD studies in many regions and applied their expertise to the development of the requirements and implementation plan. " CSU still has concerns over the carte blanc approach to rolling this standard out. Are we going to get the desired result as every entity applies this standard? We still have concerns that we will not. If there have been field tests and multiple studies it seems that there would be some conclusions or thresholds that could

		be used to provide additional applicability criteria. Is it really true that every entity in the United States needs to create these models, run these studies and assessments? There were no general applicability conclusions that would produce the data needed to focus the scope of GMD impacts into specific regions or entities with particular footprint profiles? We anticipate excessive and unnecessary resource expenditure in performing the requirements of this standard. We still have concerns that there will be significant modifications needed to the process as it is rolled out without a pilot program. Shorting the implementation period and including additional pilots we feel would yield substantial results in resource savings and additional applicability criteria.
Response: The SDT believes that all applicable entities need to perform the analyses required in the standard. The expected impacts of the Benchmark GMD event will vary widely across the North American system due to various factors, such as geomagnetic flexibility, earth conductivity, system topology, etc. The SDT believes that it has incorporated those considerations into the requirements of the standard.		
LCRA Transmission Services Corporation	No	LCRA TSC comments on requirement R5 - To clarify cases where this requirement should apply, LCRA TSC suggests the following: Each responsible entity, as determined in Requirement R1, shall provide GIC flow information (where the maximum effective GIC value is 75 A per phase or greater) to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area.
Response: The SDT believes that it is important for the entities doing the GIC calculations to provide maximum effective GIC information (part 5.1) for all applicable BES power transformers, so that the asset owner can understand the proximity of their transformers to the 75 A per phase limit. The asset owner may choose to perform thermal analysis even though the transformer may be below the threshold due to its history, for example. The suggested change would not meet the objective.		

David Kiguel	No	1. The responses to my comments in the previous posting give me no comfort. I am sure the SDT has been "cost conscious" in developing the standard. However, without a serious cost/benefit assessment there is no way of quantifying such claim. Saying that a cost/benefit analysis was not in the project scope as defined in the SAR is mistaken. The SC has, in principle, approved the CEAP project and there is no need to state explicitly in the SAR that a Cost Effective Assessment shall be performed. 2. I do not agree with the VRF change from Medium to High in Requirement 2. The High VRF definition that applies in this case (planning time frame) is a requirement that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The Medium VRF definition is a requirement that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. I believe, violation of a System Models requirement should be Medium at best.

Response:

1. The SDT is aware of several preliminary studies that have been performed by various entities in the North American system that basically carry out the calculations contemplated by the standard. Those studies underscore the difficulty of performing a detailed cost/benefit analysis in that the mitigation strategies for potentially vulnerable facilities are not immediately evident and require additional iterative studies. Relative to the benefits of GMD mitigation, it is equally difficult to project the scope (and costs) of a

voltage collapse and blackout without the detailed studies that will be required by the standard. The SDT suggests that a cost/benefit analysis will only become meaningful once the standard has been in place and entities are conducting GMD Vulnerability Assessments. 2. The change of the VRF from Medium to High is to provide consistency with the VRF for approved standard TPL-001-4 Requirement R1 which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.		
Puget Sound Energy, Inc. Public Utility District No. 2 of Grant County, WA	No	The proposed TPL-007 standard has no requirement to share GIC modeling data with neighboring PCs or other PCs in close electrical proximity. For a medium system like ours, we rely on the adjacent systems having adjacent PCs for major bulk transmission. Without appropriate modeling information from adjacent PCs GIC study results our assessments of the vulnerability of our system for GIC will be optimistic and misleading. While the standard requires us to share flawed study results with our neighboring PCs it does not address requirements to share GIC modeling data needed to correct the study deficiencies.
Response: Requirements to provide the data for power system modeling and analysis are covered under other standards. The SDT believes these requirements and planning processes are sufficient to perform GMD Vulnerability Assessments.		
OMU	No	Small entities will be required to develop and maintain models for low frequency events that have not been proved to have a high impact on a system of our magnitude.
Response: GMD events are known to have potential impact on the interconnected transmission system. Consequently, the applicability of TPL-007 is not determined by an entity's size.		
Volkmann Consulting, Inc	No	The SDT has not technically justified the Benchmark event case, both spatial averaging and scaling factor. The recent Chinese paper outline the event of a GMD event in 2005. The China paper indicates that they experiences a field of 0.67V / km. The NERC Benchmark scaling factors would have only yielded a field

		of 0.03V / km. Thus the NERC Benchmark scaling method is off by a factor of 22 times.
Response: Technical justification is provided in the benchmark GMD event white paper. The commenter's suggestion that the scaling factors do not agree by a factor of 22 with geoelectric fields in a cited paper is incorrect. Equation (2) from TPL-007 attachment 1 specifies a lower bound on the scaling factor. This lower bound scaling factor was not applied in the commenter's calculation resulting in a lower value for geoelectric field.		
Avista Utilities	No	Please consider inserting language that clearly states the following: 1. That GIC/GMD is a regional phenomenon and as such requires that the data provided for modeling GIC/GMD be regional in scope. For example, to properly model GIC/GMD in WECC ALL WECC utilities shall provide GIC/GMD modeling data. 2. Utilities shall submit Latitude & Longitude of substations (including associated buses) in order to support accurate GIC/GMD modeling. Comment: Presently there is an enormous amount of opposition to providing location data to WECC for use in power flow base cases for the purposes of modeling GIC/GMD. The excuse used is that the TPL-07 standard does not require that data (with additional security concerns about providing location data). Specifically stating the modeling data needs along with the requirement to submit said data will go a long way towards getting GIC/GMD modeling completed.
Response: The SDT does not agree with the assertion that it is necessary to model an entire Interconnection in order to accurately determine the GIC flows in a given system. Because the drivers of GIC flow in a system (e.g. system topology) tend to be more localized, modeling 2-3 buses into the neighboring system is sufficient to obtain accurate results [1],[2]. 1. Thomas Overbye, et al, “Power Grid Sensitivity Analysis of Geomagnetically Induced Currents”, IEEE Transactions on Power Systems, Vol. 28, No. 4, November 2013.		

2. NERC GIC Application Guide		
ReliabilityFirst	No	ReliabilityFirst votes in the Affirmative and believes the TPL-007-1 standard enhances reliability and establishes requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events. ReliabilityFirst offers the following comments for consideration: Requirement R7 - ReliabilityFirst still believes Requirement R7 should require the Entity to not only develop a Corrective Action Plan (CAP) but require the Entity to "Implement" it as well. ReliabilityFirst agrees that other processes outside of the standards process, such as internal investment processes for a vertically integrated entity, or regional planning processes for RTOs, regulatory processes that vary from jurisdiction to jurisdiction, etc., are factors that are considered when developing a CAP, but once the CAP is developed the entity needs to implement it. Also, in FERC Order 706, the Commission makes it clear that when discussing the CIP standards (specifically Technical Feasibility Exceptions), that an Entity is required to "develop and implement" mitigation steps, mitigation plans and remediation plans. Even though the Order does not explicitly mention the term CAP, we believe mitigation steps, mitigation plans and remediation plans are in the same vain and context of a CAP. As you can see, the implementation piece is an important component in which the Commission highlighted. Listed below are examples from the Order: FERC Order 706, paragraph 187 "As mentioned above, in the CIP NOPR, the Commission proposed a three step structure to require accountability when a responsible entity relies on technical feasibility as the basis for an exception. This proposed structure would require a responsible entity to: (1) develop and implement interim mitigation steps to address the vulnerabilities associated with each exception; (2) develop and implement a remediation plan..."

		FERC Order 706, paragraph 192 "With some minor refinements discussed below, the Commission adopts the CIP NOPR proposal for a three step structure to require accountability when a responsible entity relies on technical feasibility as the basis for an exception. We address mitigation and remediation in this section and direct the ERO to develop: (1) a requirement that the responsible entity must develop, document and implement a mitigation plan..." . Furthermore, FERC Order 706, paragraph 217 states "However, we disagree with Northern Indiana that penalties should be waived within the time when an approved remediation plan is being implemented, as proper implementation of the plan itself constitutes a necessary element of compliance." The Commission believes "proper implementation of the plan itself constitutes a necessary element of compliance" which bolsters our recommendation to include the "implementation" piece within Requirement R7.
Response: The development of a Corrective Action Plan is generally done via a collaborative process with the asset owners or in consultation with internal customers for vertically integrated entities. Specific implementation is addressed in processes that are outside of the standards process. This approach is appropriate for a planning standard and respects the diversity of mitigating measures that are possible to meet performance requirements during a benchmark GMD event. These measures may include operating procedures, hardware mitigation, or equipment upgrades, which involve various entities, timelines, and coordinating actions among collaborating stakeholders. TPL-007 maintains accountability for meeting performance through R7 part 7.2, which specifies that the planning entity must review corrective actions in subsequent GMD Vulnerability Assessments until performance requirements are met.		
California ISO	No	1. The California ISO recommends that a new requirement be added to the TPL-007-1 Standard requiring: Generator Owners and Transmission Owners shall be required to provide necessary transformer data for the GIC-models to the Planning Coordinators and Transmission Planners. The California ISO recommends the above requirement recognizing that the source of the transformer data and GIC-model data is generally the Transmission Owners and

		Generator Owners. This recommended additional requirement for TOs and GOs would ensure that the data needed to conduct the studies is provided to Planning Coordinators and Transmission Planners. 2. In addition, the California ISO supports the following portion of the Standards Review Committee's comments on this question: The SRC appreciates the revisions provided in Requirement R6, but recommends that the ability of entities to collaborate and coordinate on the performance of jointly-owned equipment be further clarified. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 75 A per phase or greater. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 75 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5; 6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

		6.4. 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. Corresponding revisions for associated measures and VSLs are also recommended. 3. Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised. 4. 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. Specifically, Table 1 provides: "Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event". However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess "Misoperation due to harmonics". The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked.

Response:

1. Requirements to provide the data for power system modeling and analysis are covered under other standards. The SDT believes these requirements and planning processes are sufficient to perform GMD Vulnerability Assessments and include Generator Owners and Transmission Owners as suggested by the commenter.

2. The SDT considered the proposed wording to Requirement R6 for jointly-owned transformers. As written, the requirement does not preclude coordination among joint owners in conducting a thermal impact assessment. The suggested change was not accepted by the SDT because it weakens the overall requirement and makes responsibility for the required action unclear. 3. The GIC calculations specified in Requirement R5 can be performed by the planning entity once dc models have been developed in Requirement R2. It is not necessary or correct to make the requirement to provide GIC flow information effective after the requirement to conduct a GMD Vulnerability Assessment becomes effective. 4. The SDT believes the suggested language for Table 1 is not sufficiently clear on what may be needed by the planner and could result in an unintended requirement being placed on owners. As written, Table 1 provides planning entities with flexibility to apply reasonable engineering judgment to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis. Data for power system modeling and analysis are covered under other standards which could be used by the planner to support TPL-007 requirements.		
Electric Reliability Council of Texas	No	1. The SRC appreciates revisions that have been made to the Standard in response to its comments, but respectfully submits that additional revisions are necessary as discussed below. The SRC reiterates the importance of recognizing the source of modeling data, which is generally the applicable Transmission Owner and Generator Owner. This addition is recommended to ensure that the data needed to conduct the studies is provided. The below revisions are proposed: R1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall delineate the individual and joint responsibilities of the Planning Coordinator and these entities in the Planning Coordinator's planning area for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s). [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]

		M1. Each Planning Coordinator and the Transmission Planners, Transmission Owners, and Generator Owners within its Planning Coordinator Area shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and copies of procedures or protocols in effect that identifies that an agreement has been reached on individual and joint responsibilities for maintaining models and performing the studies needed to complete GMD Vulnerability Assessment(s) in accordance with Requirement R1.Corresponding revisions to VSLs are also recommended. 2. The SRC appreciates the revisions provided in Requirement R6, but recommends that the ability of entities to collaborate and coordinate on the performance of jointly-owned equipment be further clarified. The following revisions are proposed: R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 75 A per phase or greater. For jointly-owned applicable Bulk Electric System power transformers where the maximum effective geomagnetically-induced current (GIC) value provided in Requirement R5 part 5.1 is 75 A or greater per phase, the joint Transmission Owners and/or Generator Owners shall coordinate to ensure that thermal impact assessment for such jointly-owned applicable equipment is performed and documented results are provided to all joint owners for each jointly-owned applicable Bulk Power System power transformer. The thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 6.1. Be based on the effective GIC flow information provided in Requirement R5;

		6.2. Document assumptions used in the analysis; 6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and 6.4. 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. Corresponding revisions for associated measures and VSLs are also recommended. 3. Implementation times for the first cycle of the standard are uncoordinated. More specifically, Requirement R5 would be effective after 24 months, but compliance therewith requires data from Requirement R4, which is effective after 60 months. The SRC respectfully recommends that these implementation timeframes be revisited and revised. 4. 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. Specifically, Table 1 provides: ”Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event”. However, the GMD Planning Guide at Sections 2.1.4, 4.2 and 4.3, does not discuss how to assess “Misoperation due to harmonics”. The harmonics content would be created by the GIC event, but it is not clear how calculation and evaluation of harmonics load flow or its effects on reactive devices. We recommend the following be added to Table 1: TOs to provide PCs with transmission equipment harmonic current vulnerability data if asked.
1. Requirements to provide the data for power system modeling and analysis are covered under other standards. The SDT believes these requirements and planning processes are sufficient to perform GMD Vulnerability Assessments, and include Generator Owners and Transmission Owners as suggested by the commenter.		

2. The SDT considered the proposed wording to Requirement R6 for jointly-owned transformers. As written, the requirement does not preclude coordination among joint owners in conducting a thermal impact assessment. The suggested change was not accepted by the SDT because it weakens the overall requirement and makes responsibility for the required action unclear. 3. The GIC calculations specified in Requirement R5 can be performed by the planning entity once dc models have been developed in Requirement R2. It is not necessary or correct to make the requirement to provide GIC flow information effective after the requirement to conduct a GMD Vulnerability Assessment becomes effective. 4. The SDT believes the suggested language for Table 1 is not sufficiently clear on what may be needed by the planner and could result in an unintended requirement being placed on owners. As written, Table 1 provides planning entities with flexibility to apply reasonable engineering judgment to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis. Data for power system modeling and analysis are covered under other standards which could be used by the planner to support TPL-007 requirements.		
Texas Reliability Entity, Inc	No	Comments: 1. Requirement R3: Texas Reliability Entity, Inc. (Texas RE) requests the SDT consider and respond to the concern that GMD criteria in the proposed standard for steady state voltage performance is different than the steady state voltage performance criteria in other TPL standards or the SOL methodology. GMD events will typically not be transient in nature so adopting the steady state approach is preferable as it would simplify the studies if the voltage criteria between GMD events and other planning events were the same. 2. Requirement R7: Texas RE intends to vote negative on this proposed standard solely on the basis that we remain unconvinced that the proposed standard meets the intent of FERC Order 779. Paragraph 79 for the following reasons: (A) Reliance on the definition of Corrective Action Plans (CAP) in the NERC Glossary in lieu of including language in the requirement appears insufficient to address the FERC statement that a Reliability Standard require owners and

		operators of the BPS to "develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event." While Texas RE agrees that requiring the development of a CAP in Requirement R7 meets part of the FERC directive, R7 falls short as there is no language in the requirement (and therefore the standard) that addresses completion of the CAP. The CAP definition calls for an associated timetable but does not address completion. Coupled with the language in R7.2, that the CAP be reviewed in subsequent GMD Vulnerability Assessments, it is conceivable that a CAP may never get completed as timetables can be revised and extended as long as the deficiency is addressed in future Vulnerability Assessments. Without a completion requirement, a demonstrable reliability risk to the BES may persist in perpetuity. Texas RE recommends the SDT revise Requirement R7.2 as follows: "Be completed prior to the next GMD Vulnerability Assessments unless granted an extension by the Planning Coordinator." (B) The language in R7.1 does not appear to adequately address the FERC statement that "Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." While R7.1 lists examples of actions needed to achieve required System performance, it does not expressly restrict a CAP from only including revision of operating procedures or training. In addition, Table 1 language regarding planned system adjustments such as transmission configuration changes and redispatch of generation, or the reliance on manual load shed, seem to contradict the FERC language regarding the limiting plans to considering operational procedures. Texas RE suggests the revising the language

		of R7.1 as follows: "Corrective actions shall not be limited to considering operational procedures or enhanced training, but may include:" Alternatively, Texas RE suggests the addition of language to the Application Guidelines for Requirement R7 reinforcing FERC's concern that CAPs "must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of any benchmark GMD event based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment." 3. Compliance Monitoring Process Section: Evidence Retention. Texas RE remains concerned about the evidence retention period of five years for the entire standard. (A) Texas RE reiterates the recommendation that the CAP should be retained until it is completed. The SDT responded to Texas RE's first such recommendation with the following response: "The evidence retention period of 5 years supports the compliance program and will provide the necessary information for evaluating compliance with the standard. The SDT does not believe it is necessary to have a different retention period for the CAP because a CAP must be developed for every GMD Vulnerability Assessment where the system does not meet required performance." With a periodic study period of five years, a CAP may extend significantly beyond the five-year window, especially in cases where equipment replacement or retrofit may be required. A retention period of five years could make it difficult to demonstrate compliance and could potentially place a burden on the entity as they will be asked 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. (B) Texas RE also recommends revising the evidence retention to cover the period of two GMDVAs. The limited evidence retention period has an impact on

		determination of VSLs, and therefore assessment of penalty. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained.

Response:

1. The SDT provided flexibility to the planning entities to establish steady state voltage performance criteria that may differ from those used in other planning analyses due to the nature of GMD events. A planning entity is not precluded from using the same steady state voltage criteria for GMD Vulnerability Assessments and other planning events.

2(A). The SDT does not agree with the suggested change to requirement R7 that would specify completion requirements for Corrective Action Plans. As written, the standard provides the necessary flexibility for developing viable timelines for mitigation actions which may come in various forms such as operating procedures, hardware mitigation, or equipment upgrades. Although flexible, the proposed standard also holds planning entities accountable for meeting system performance requirements by requiring the CAP to be reviewed in subsequent GMD Vulnerability Assessments. This provides for various mechanisms of accountability to be employed to obtain assurance of implementation. The SDT believes this is an appropriate approach for a planning standard with diverse mitigation options, and that it is the most effective and efficient way to meet the reliability objectives.

2(B). The SDT has revised the rationale box for Requirement R7 to address the concern.

Rationale for Requirement R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:
A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the Benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force GMD Planning Guide provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7 Part 7.3 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

3. Evidence retention periods were revised as recommended by Texas RE in the third posting.		
Bureau of Reclamation	No	The Bureau of Reclamation does not agree that a Responsible Entity should have the power to obligate Transmission Owners (TOs) or Generator Owners (GOs) to take actions under a Corrective Action Plan (CAP) under R7 unless the TOs and GOs agree to the CAP. A mere requirement to respond to comments is not sufficient to ensure that costs will not outweigh anticipated reliability benefits under a results-based approach. Reclamation continues to believe that R7 should require the affected Transmission Owner and Generator Owner to agree on actions and timeframes in a CAP.
Response: The SDT did not intend to establish requirements for the implementation of the Corrective Action Plan in this standard because the implementation would be addressed in processes that are outside of the standards process. The standard requires the preparation of a Corrective Action Plan (CAP) for situations where system performance cannot be met during the Benchmark GMD conditions. However, as with other TPL standards, the standard does not address the specific execution of the CAP or obligations of other entities. As written the requirement is clear, results-based, and reflects the correct functional entities per the NERC functional model. The suggested wording to require TO and GO agreement on actions in the CAP would result in a weaker requirement that does not meet NERC guidelines for quality. Nonetheless, the SDT believes that development of the GMD Corrective Action Plan will require a collaborative process outside of this standard. To do otherwise would grant additional authority to the planning entities that was not intended and which they do not possess today.		
Northeast Utilities	No	1. NU supports NPCC's comments as they relate to the consideration of the impact of Underground Pipe-type cables. NU seeks clarification on if SDT evaluated Solid Dielectric type cables. If not, why. 2. The proposed standard is written presents the potential for competition conflicts under FERC Order 1000 for Requirement 4.3, 6.4, 7.3. Clarification to this effect should be captured in either the requirements themselves or the application guidelines to mitigate any potential conflicts.

Response: 1. The SDT maintains that underground pipe-type transmission lines are a necessary component of the dc network and therefore cannot be excluded from the proposed standard. The following has been added to the guidelines and technical basis section for R2: Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable. Evaluation of specific dc characteristics is modeling issue that should be addressed further in modeling guidance and not as part of the standards development process. 2. FERC Order No. 1000 established requirements for transmission cost allocation and transmission planning reforms. Information sharing required by the proposed standard is necessary for reliability and can be accomplished without presenting any market or competition-related concerns. Furthermore, the proposed standard is consistent with Order No. 672.		
Foundation for Resilient Societies	No	Supplemental Comments of the Foundation for Resilient Societies on NERC Standard TPL-007-1Transmission System Planned Performance for Geomagnetic Disturbance Events November 21, 2014 The Foundation for Resilient Societies, Inc. [hereinafter “Resilient Societies”] separately files today, November 21, 2014 Group Comments that assert multiple failures, both procedural and substantive, that result in material noncompliance with ANSI Procedural Due Process, and with NERC’s Standard Processes Manual Version 3, effective on June 26, 2013. In this separate Supplemental Comment, Resilient Societies incorporates as its concerns the material in comments on NERC Standard TPL-007-1 submitted by John Kappenman and William Radasky (July 30, 2014); John Kappenman and Curtis

		Birnbach (October 10, 2014); John Kappenman (2 comments dated November 21, 2014); and EMPrimus (November 21, 2014). We reserve the right to utilize all other comments filed in the development of this standard in a Stage 1 Appeal under NERC's Standard Processes Manual Version 3. In particular but not in limitation, we assert that NERC fails to collect and make available to all GMD Task Force participants and to utilize essential relevant data, thereby causing an unscientific, systemically biased benchmark model that will discourage cost-effective hardware protection of the Bulk Power System; that NERC fails to fulfill the obligations under ANSI standards and under the Standard Processes Manual to address and where possible to resolve on their merits criticisms of the NERC Benchmark GMD Event model. Moreover, if the NERC Director of Standards and Standards Department fail to exercise the "quality control" demanded by the Standard Processes Manual, this will also become an appealable error if the standard submitted on October 27 and released on October 29, 2014 becomes the final standard for the NERC ballot body. Moreover, an essential element of quality control for NERC standard development and standard promulgation is that the Standard comply with the lawful Order or Orders of the Federal Energy Regulatory Commission. To date, no element of the standard performs the cost-benefit mandate of FERC Order. No. 779. Resilient Societies hereby refers the Standards Drafting Team and the NERC Standards Department to the filing today, November 21, 2014 of Item 31 in Maine Public Utilities Commission Docket 2013-00415. This filing is publicly downloadable. Appendix A to this filing of as Draft Report to the Maine PUC on geomagnetic disturbance and EMP mitigation includes an assessment of avoided costs, hence financial benefits of installing neutral ground blocking devices, including a range of several devices (Central Maine Power) to as many as 18 neutral ground blocking, and GIC monitors (EMPrimus Report, November 12, 2014, Appendix A in the Maine PUC filing of November 21, 2014). Cost-benefit analysis

		could and should be applied on a regional basis, in the NERC model and with criteria for application by NERC registered entities. NERC has failed to fulfill its mandate, with the foreseeable effect of suppressing public awareness of the benefits resulting from blockage of GICs to entry through high voltage transmission lines into the Bulk Power System. Another foreseeable result is economic harm to those companies that have invested capital in the development of GMD hardware protection devices and GIC monitors. We incorporate by reference the materials in Maine PUC Docket 2013-00415, Items 30 and 31, filed and publicly retrievable online in November 2014. Finally, we express concern that the combination of NERC Standards in Phase 1 and in Phase 2, providing no mandatory GIC monitor installations and data sharing with Regional Coordinators, and with state and federal operations centers, effectively precludes time-urgent mitigation during severe solar storms despite timely reports to the White House Situation Room. NERC has effectively created insuperable barriers to fulfill the purposes of FERC Order No. 779. Without significant improvements that encourage situational awareness by Generator Operators and near-real-time data to mitigate the impacts of solar geomagnetic storms, the only extra high voltage transformers that can be reliably protected will be those with installed hardware protection. Yet this defective standard will provide false reassurance that no hardware protection is required. Also, the scientifically defective NERC model may also preclude regional cost recoveries for protective equipment, by falsely claiming that no protective equipment is required under the assessment methodologies in the standard. Hence irreparable harm to the reliability of the Bulk Power System, and to the residents of North America, is a foreseeable result of the process and substantive result of this standard. Respectfully submitted by:

		Submitted by: Thomas S. Popik Chairman Foundation for Resilient Societies William R. Harris International Lawyer Secretary, Foundation for Resilient Societies

Response: Thank you for your comments and for your continued participation in the standards development process. The SDT has reviewed your comments.

1. NERC and the Standards Drafting Team have followed the NERC Standards Process Manual, which is approved by ANSI, throughout the development of TPL-007. The drafting team has made a good faith effort to resolve all objections to the proposed standard and responded in writing to submitted comments. For these reasons, no procedural failures have occurred in the development of TPL-007.

2. Thank you for bringing attention to the draft report in Maine PUC docket 2013-00415. The SDT solicited stakeholder comments on cost considerations and has proposed a standard that provides performance requirements but is not prescriptive on mitigation strategies or technologies. This SDT believes this approach, which is consistent with other planning standards, is the most cost effective means to accomplish the reliability objectives and is technology-neutral. Further, this approach complies with Order No. 779. Paragraph 28 states: “We expect that NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards.” NERC and the industry have considered the costs and benefits associated with TPL-007-1. Order No. 779 does not include a “cost-benefit mandate.” Indeed, the Commission disagreed that section 215 of the FPA requires a particular cost-benefit showing.

3. The approved Stage 1 standard, EOP-010-1, addresses operating plans, processes, and procedures for mitigation of GMD events. Proposed standard TPL-007 requires entities to develop mitigation plans to address identified impacts from the benchmark GMD event but does not impose prescriptive mitigation strategies. The SDT's approach allows applicable entities to decide how to mitigate

GMD vulnerabilities on their systems. GIC monitoring may be a component of an entities mitigation plan as discussed in technical supporting material including the GMD TF GMD Planning Guide and the 2012 GMD Report.		
Iberdrola USA	Yes	The NERC drafting committee has done an excellent job creating the TPL-007-1 standard. Iberdrola USA has two areas that we are requesting further explanation on. 1. Please provide additional clarity on the amount devices removed from service as part of Table 1. A whitepaper or footnote on identification, number of devices and design considerations would be helpful. For example, consideration of Wye grounded capacitor banks with electromechanical relays vs. microprocessor controlled/protected ungrounded capacitor banks and they amount to remove. 2. The development of Corrective Action Plans has the same date as the completion of the GMD assessment. It would be helpful to lay out when the facilities/equipment identified in CAPs would need to be in-service. It is impossible to have a CAP that needs facility installations to be completed at the same time as an assessment has just identified the issues.
Response: 1. The SDT has reviewed your comment and does not believe that a footnote or additional white paper are appropriate. As written, the standard provides flexibility for planners to apply engineering judgment and is appropriately supported by technical resources including the NERC GMD TF GMD Planning Guide (section 4.2 and 4.3) and the 2012 GMD Interim Report (Section 6.4). A prescriptive tool or method as suggested by the commenter would not be effective in application to all planning entities. 2. The proposed standard does not specify a completion date for corrective actions because there may be a variety of factors for a planning entity to consider in evaluating the various mitigation strategies. The planning entity has flexibility to include an appropriate timeline in the Corrective Action Plan.		
OG&E	Yes	The changes in the Standard to date are a significant improvement over the prior versions. That being said, the Standard still places a substantial burden on

		Transmission Planners whose operating areas are not located in areas that, due to latitude and soil types, are not generally considered vulnerable to GMD. There should be some screening criteria for GMD vulnerability that would not require burdensome iterative studies for TPs whose facilities are not located in geographical areas not generally considered impacted by GMD events.
Response: The SDT does not have sufficient data to be able to propose an exemption from the requirements of the standard to any portion of the North American transmission system.		
Duke Energy	Yes	Duke Energy suggests adding the following provision in the rationale box of R5 that is in the rationale box of R6: "The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information."
Response: The SDT has reviewed the comment and will modify the Rationale for Requirement R5 as follows: Rationale for Requirement R5: This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD. The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. GIC(t) provided in Part 5.2 ~~is~~ can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-DisturbanceMitigation.aspx		

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1. The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.		
SERC PSS	Yes	While we agree with the changes made to the draft standard, we still believe that the magnitude of the benchmark GMD event is too great. We also remain concerned with respect to the amount of resources which will be needed to complete the necessary modeling and assessment work. 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.
Response: The SDT responds that the Benchmark GMD event was established based on a statistical analysis of actual magnetometer readings over a span of 20 years. Due to the potential wide-area impact of GMD events, the SDT believes a 100-year scenario is an appropriate benchmark.		
Bonneville Power Administration	Yes	1. BPA requests that R4.3 be clarified. Completion of the vulnerability assessment starts the 90 day clock for distribution of the results to adjacents. If another functional entity (not an RC, adjacent PC or TP) submits a written request for the results, say 100 days after completion, is the responsible entity at risk of a compliance violation because they were unable to provide the assessment within the 90 day required time frame? BPA suggests the 90 calendar day requirement be bifurcated from the requirement to respond to a written request from a functional entity. 2. Proposed revisions:

		R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area. 5.2. The GIC flow information shall also include the effective GIC time series, GIC(t), (calculated using the benchmark GMD event described in Attachment 1), in response to a written request from any Transmission Owner and Generator Owner with applicable facilities in the planning area. The GIC(t) shall be provided within 90 calendar days of receipt of the written request. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1. BPA requests the above clarifying changes be made to R5 and parts 5.1 and 5.2. We believe the changes clarify the required actions in R5 and parts 5.1 and 5.2 without compromising SDT intent. R5 - "Applicable facilities" are defined in section 4.2 of the standard so the struck sentence seems redundant and confusing. 5.1 - Please strike second sentence as TO, GO and applicable facilities are already called out in the actual requirement (R5).

		5.2 - Since the 90 day clock begins ticking after determination of the maximum effective GIC value in 5.1, changes requested reflect this. 3 - BPA is concerned that, under extreme conditions, R7 may require entities to implement Corrective Action Plans that require shutting down or islanding their transmission systems, in order to meet the performance requirements of Table 1. 4 - BPA also suggests adding a comma to R 7.1, third bullet, following the word, “Procedures.” 5 - Table 1 - Steady State Planning Events under the Event column indicates that facilities removed as a result of protection system operation or misoperation due to harmonics during GMD event need to be modeled. There seem to be three options to perform the required assessment: 1. Perform harmonic studies to justify not taking the var devices outage analysis or 2. Replace all mechanical relays with microprocessor relays that have the capability to block harmonics or 3. Remove all SVCs or shunt caps and perform the assessment. BPA believes Option 1 is not practical for the Transmission Planner to perform harmonic analysis for the entire system due to lack of tools and expertise. Option 2 is an expensive solution for a one in a hundred year event. Utilities do not build for extreme contingencies such as a one in ten probability event. Removing all reactive devices under Option 3 defeats the purpose of installing these reactive devices. BPA suggests that this low probability extreme GMD event be evaluated under normal system conditions, not under system contingency events. 6 - Additionally, the SDT provided this response to BPA’s comment during the last period: “The SDT agrees with comments on the limitations of commercial tools. TPL-007 requirements can be met with existing tools and techniques.” BPA requests the GMD taskforce provide any existing tool(s), such as a spreadsheet calculator, with the functionality to evaluate the thermal, reactive, or harmonic, impact of GIC on a transformer and identify the tool(s) required to perform harmonics analysis of reactive elements such as shunt capacitors and SVCs. These

		study tools are described as available, but it is not clear what they actually are and BPA would like to be certain that any assessments done are done so in a constant manor by all infrastructure owners that that this standard applies to.
Response: 1. The SDT has reviewed the comment regarding R4.3 and believes that the requirement as written is clear. The comment refers to requests that are outside the 90 day period. Such requests should be easy to fulfill, given that the analysis would have already been complete. 2. The SDT is averse to making the change to R5 because it would change the intent of the SDT. While non-BES transformers are to be included in the modeling and GIC calculation, the intent is to have the network analysis and potential mitigation only apply to BES transformers. Therefore, using the Applicable Facilities definition would change the SDT intent. Regarding the suggested changes to 5.1 and 5.2, the SDT added the second sentence in 5.1 based on previous comments to provide additional clarity. The suggested comment to 5.2 is addressed in the Rationale for Requirement R5. 3. The CAP developed under R7 must address how the performance requirements of Table 1 will be met. A CAP that requires shutting down or islanding the transmission system would not meet the requirements of Table 1. 4. Regarding the suggested edit to 7.1, we will implement that suggestion. 5. Replacement of all protective relays or outaging all relays in the power flow case are extreme reactions to the uncertainty associated with harmonics. The SDT believes that some reasonable engineering judgment can be exercised by protection engineers to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis. Loss of reactive compensation that has a high likelihood of tripping due to harmonics is an event that must be evaluated as part of the GMD Vulnerability Assessment because it is a known risk from GMD. 6. The SDT acknowledges the tools to perform detailed harmonics analysis are not in wide availability in the industry. As written, the standard provides flexibility for planners to apply engineering judgment and is appropriately supported by technical resources including the NERC GMD TF GMD Planning Guide (section 4.2 and 4.3) and the 2012 Interim Report (section 6.4).		
Manitoba Hydro	Yes	On the whole, changes made to TPL-007-1 were errata with the exception of the thermal assessment screening criteria. The suggested changes are acceptable. In

		previous comment forms, the SDT proposed the following question, which was missing in this comment form. Manitoba Hydro believes there still are outstanding issues needing to be addressed. Manitoba Hydro has two main concerns with the proposed standard that prevent it from voting affirmative: 1. Thermal Assessments not tied back to GMD Vulnerability Assessment - The SDT has explained in the rationale to R6 the fact that issues identified in the thermal impact assessment should be included in the GMD vulnerability assessment and corrective action plan, however, there needs to be corresponding language in the requirements to make this action occur. This approach is important because the Planning Coordinator is in the best position to take a wide area view to determine if the suggested actions by the TO/GO are appropriate to add to the Corrective Action Plan or whether other actions should be taken. Suggested changes: - Requirement R6.4: Remove “performed and” from this requirement as it is redundant. Requirement R6 already requires the TO and GO to conduct the assessment.- Add a new requirement R4.4: “The study or studies shall include the results from the thermal impact assessment performed in Requirement R6 and determine whether the System meets the performance requirements in Table 1.” Transformers that have been determined to be vulnerable should be tripped as part of the Event in table to determine ability to meet performance requirements. If performance is not met, the PC should determine the appropriate Corrective Action Plan, which includes investigating any of the TO/GO’s suggested actions from the thermal impact assessment. - Revise the Event description in Table to: “Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics or thermal overload during the GMD event.” This clarifies the intent of the SDT to ensure that event includes

		simultaneous loss of all devices including those identified in the thermal assessment. 2. Lack of Harmonic Analysis Tools may make the Event in Table 1 too severe - At present, there are no harmonic analysis tools that are capable of efficiently modeling the Planning Coordinator area to determine the impacts of harmonics on Protection Systems and other Transmission Facilities (eg. HVdc converters). These tools may develop over the five-year implementation period of the GMD standard, however there are no guarantees. In the absence of harmonic analysis, the SDT wants the Event in Table 1 to include simultaneous loss of all Reactive Power compensation devices and other Transmission Facilities. This is potentially too severe an event to develop a Corrective Action Plan for. Manitoba Hydro is willing to include the analysis of such an event but would recommend that it be a categorized as an extreme event (as per TPL-001-4). If Cascading occurs, then an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event shall be conducted. The event in Table 1 should be modified to possibly two (credible event and an extreme event) or a note could be added to the event such as: - Note 4: In the absence of a harmonic assessment, complete simultaneous loss of all Reactive Power compensation and other Transmission Facilities is considered an extreme event and If Cascading occurs, then an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event shall be conducted. At minimum, loss of all Reactive Power compensation and other Transmission Facilities vulnerable to Protection System operation or Misoperation within a single substation shall be removed during the GMD event plus any transformers determined to be overloaded in a thermal impact assessment.

Response:

1. The SDT does not support adding prescriptive language to the standard for how the thermal assessment results are incorporated into the GMD VA and believes the rationale box is sufficient. The entity responsible for performing a GMD VA must consider the

information provided in Requirement R6. A GMD VA is defined as: *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.* The following is part of the rationale box for R6: *Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.* 2. Regarding the comments on harmonics analysis, the SDT acknowledges the tools to perform detailed harmonics analysis are not in wide availability in the industry. However, replacement of all protective relays or outaging all relays in the power flow case are extreme reactions to the uncertainty associated with harmonics. The SDT believes that reasonable engineering judgment can be exercised to identify protection equipment that may be vulnerable to misoperation in the Benchmark GMD event and therefore, should be outaged in the power flow analysis.		
American Electric Power	Yes	It is unclear from the current wording whether the 24 month timing of completion of R6 begins with a) the receipt of the information in R5.1 or b) the receipt of information requested under R5.2. AEP recommends the SDT clarify within the standard.
Response: The SDT has clarified that the 24-month timeline for R6 is based on receipt of GIC information provided in Requirement R5 part 5.1. See summary consideration for the revised language.		
Public Service Enterprise Group	Yes	It would be helpful to understand whether the GMD Vulnerability Assessment will be factored into such items as generation interconnection requests or transmission expansion planning, and if so, how it will be incorporated. In other words, will a GMD Vulnerablity Assessment be added to traditional planning studies (i.e., load flow, dynamic, and short circuit)? Also, is additional GMD-related modelling data expected to be requested from assest owners? For example, transformer thermal capabilities, grounding resistance, transformer type (shell/core) are not requested presently.

Response: The SDT does not have additional insights into the potential uses of the GMD VA. Planning entities may need to obtain GMD-related modeling information such as resistances for dc network model.		
Ameren	Yes	While we agree with most of the changes made to the draft standard, we still believe that the magnitude of the benchmark GMD event is too great. In addition, we also remain concerned about the amount of resources, which will be needed to complete the necessary modeling and assessment work.
Response: The SDT responds that the Benchmark GMD event was established based on a statistical analysis of actual magnetometer readings over a span 20 years. Due to the potential wide-area impact of GMD events, the SDT believes a 100-year scenario is an appropriate benchmark. The SDT appreciates industry input throughout the standard development process to reach the right balance of resources to meet the reliability objectives of TPL-007.		
Tacoma Power	Yes	Tacoma Power appreciates the opportunity to comment and had the following comments regarding VSLs for the standard. The implementation for R5 allows 24 months to implement, and 90 days to respond to a request, but the difference between a lower and medium VSL is only 10 days. We suggest using the same grading as in MOD027-1 of 90, 180, and 270 days. Requirement R6 allows 24 months to complete the study, but the difference between a lower and medium VSL is just 2 months. We suggest using the same grading as in MOD-030 of 3,6, and 9 months.
Response: The SDT does not agree with the proposed VSL changes. Timely completion of Requirements R5 and R6 are necessary for executing the GMD Vulnerability Assessments within a 60-month period. The VSLs in the proposed standard are consistent with other standards.		
Seminole Electric Cooperative, Inc		1. Seminole requests the drafting team explain in more detail why the resistivity values were calculated via geometric mean calculation as opposed to arithmetic mean calculation if you are just dealing with one category of values (i.e. with the same units) for the Florida peninsula? Seminole cannot determine from the

		short write-up provided by USGS via the drafting team shortly before ballot closing what all of the factors are that went into some of the resistivity mean calculations, e.g., are the factors just resistivity values or was layer thickness included. 2. Seminole requests more data on how the interim layer for layers 1 and 2 was calculated. The short write-up provided by USGS via the drafting team shortly before ballot closing does not appear to include this information. 3. Seminole requests the drafting team provide a Florida ground model illustration that includes the naming of the layers akin to what USGS has posted for other regions. It appears that layer four is the upper mantle, but it is unclear what are the other layers. 4. Seminole reiterates its request that the drafting team perform a CEAP for this Standard. 5. Seminole requests the drafting team post this Standard for a full additional comment period of 45 days. The full time period is needed, especially for Florida, as the Florida beta factor was revised by the drafting team from 0.94 to 0.74. In addition, the amps per phase amount cited in Requirement R5 was revised from 15 A to 75 A. Such major revisions reflect the need for additional review by the drafting team and balloting members. 6. Seminole has concern on whether the drafting team followed the NERC Standard Drafting Procedure by not providing the Florida ground model information at the time of balloting as stated in the proposed Standard. The Florida ground model information was not distributed until approximately ten (10) days after posting via a webinar, which left Florida utilities approximately 15 days to review and comment. Seminole believes that all information that the Standard depends on needs to be posted at the time of ballot in order to meet the ANSI Standards which NERC is attempting to emulate along with the NERC

		Standard Drafting Process. A review of USGS Regional Conductivity Maps webpage, linked to in the Standard, shows that on November 14, 2014 that Florida's data has still not been posted on the website. 7. Seminole proposed that NERC include the opportunity for "regions" to "test outâ€? the TPL-007-1. By that, Seminole means that certain "regions" would perform the initial analyses for TPL-007-1 and if none of the transformers within a "region" had GIC values above 75 A/phase in accordance with Requirement R5, then entities would not need to perform studies again for those transformers in that "region" until NERC/FERC developed reasons why the circumstances have changed and a study needs to be performed again, i.e., no requirement to perform the study every 5-years unless circumstances have changed. As far as what a "region" constitutes, Seminole suggests that a "region" be defined as a NERC Region, e.g., FRCC, TRE, SPP RE, etc.

Response:

1-3. These comments have been referred to USGS individuals who are qualified to address them. A technical basis for the Florida ground model description was provided by USGS and cited available information and reports. The standard allows entities to use justified alternative ground models in GMD Vulnerability Assessments, which provides a means for entities to obtain more refined or exact models for their specific location.

4. The SDT is aware of several preliminary studies that have been performed by various entities in the North American system that basically carry out the calculations contemplated by the standard. Those studies underscore the difficulty of performing a detailed cost/benefit analysis in that the mitigation strategies for potentially vulnerable facilities are not immediately evident and require additional iterative studies. Relative to the benefits of GMD mitigation, it is equally difficult to project the scope (and costs) of a voltage collapse and blackout without the detailed studies that will be required by the standard. The SDT suggests that a cost/benefit analysis will only become meaningful once the standard has been in place and entities are conducting GMD Vulnerability Assessments.

5. NERC, the SDT, and Standards Committee (SC) liaison obtained SC authorization for shortened comment period to meet a regulatory deadline after providing notification to stakeholders as required by the Standards Process Manual. 6. TPL-007 has been developed in accordance with NERC Standards Process Manual. The SDT reiterates that the beta scaling factor is a default based on publicly available information. The standard allows entities to use justified alternative ground models in GMD Vulnerability Assessments. 7. System changes that are best understood by the planner may affect GMD Vulnerability Assessment results. The proposed standard is consistent with other standards in requiring periodic reevaluation. Additionally, the 75A per phase criterion applies to transformer thermal impacts but does not indicate immunity to potential system voltage or harmonic impacts.		
SPP Standards Review Group		We have a concern about clarity for Requirement R3 in reference to Table 1. In the actual requirement, it mentions having criteria for acceptable System steady state voltage performance in reference to the benchmark GMD event described in Attachment 1. However in the Rationale Box, we're not sure what's the signifigance of Table 1. Also, you mention in the Rationale Box for Requirment R4 (the last sentence) "Performance criteria are specified in Table 1". We ask the drafting team to provide more detail and clarity on the impact of Table 1 on the development of performance criteria in the Rationale Boxes for Requirements R3 and R4.
Response: Requirement R3 specifies that the designated planning entity will establish steady state voltage performance criteria for GMD planning. Table 1 provides details on the GMD planning event. The performance criteria and planning event are components of the GMD Vulnerability Assessment specified in Requirement R4.		
Seattle City Light	Yes	Seattle City Light appreciates the efforts of the Drafting Team to include language supporting regional-scale studies, which will be essential to achieving a sound understanding of GMD effects in WECC.
Ingleside Cogeneration LP	Yes	As with many other respondents to the previous draft of TPL-007-1, ICLP is trusting that Compliance Enforcement Authorities will apply reasonable

		consideration of the state of scientific understanding of the GMD phenomena during audits. Even though the requirements are written in a zero-tolerance fashion, it is our understanding that FERC recognizes that performance expectations will evolve as our cumulative experience grows over time. It would be inappropriate for CEAs to assess penalties for action or non-action that no Registered Entity could possibly anticipate. We are willing to proceed based upon our perception that the ERO will implement this Standard in a fair and even-handed way - but suggest that it may not be easy to keep that reputation if trust is violated.
Response: The SDT agrees with the comment and trusts that compliance will understand the "state of the art" regarding the ability to perform these analyses.		
John Kappenman, Storm Analysis Consultants and Curtis Birnbach, Advanced Fusion Systems		Comments Regarding NERC Draft Standard on GIC Observations and NERC Geo-Electric Field Modelling Inaccuracies (appended to this report)
Response: The commenters use the terms/concepts of models and input data interchangeably. The commenters assert that the models used by the SDT are flawed and consistently under predict the geoelectric field. This is simply not the case. The models and simulation techniques used to develop the benchmark GMD event are known throughout the scientific community as being state-of-the-art. The input data (e.g., earth models) that were used in the analysis represent the best available in the public domain. The models, methodology and input data that were used to develop the benchmark event have been detailed in numerous white papers and electronic data files and have been made available to the public. However, the details of the models and input data used to develop the response by the commenters have not been described or made available to the SDT for review; thus, limiting the ability of the SDT to perform an independent review of the commenter's simulation results and analysis.		

The commenters suggest that the way to overcome the perceived modeling errors is to examine GIC data that are available throughout the United States and Canada. As noted previously, the simulation methods used by the SDT are not in error; however, without local geomagnetic field measurements, exact information on the power system at the exact time of the measurements, and consistent data acquisition rates, GIC measurements alone cannot provide any usable information regarding the accuracy of models, simulation methods or input data that are used to perform GMD vulnerability assessments or to develop severe GMD event scenarios. See previous comment response regarding the detailed information that is required to perform validation of models and input data.		
Representative Andrea Boland Sanford, Maine		Supplemental Comment (appended to this report)
Response: Thank you for participating in the standards development process and sharing your insights.		
Gale Nordling, EMPrimus		NERC Geomagnetic and Geoelectric Field Benchmark Model and Recommendations (appended to this report)
Response: 1. Thank you for your continued participation in the standards development process. The SDT has responded to prior comments. 2A. The SDT revised the thermal screening criterion from 15 A per phase to 75 A per phase after conducting extensive simulation of the benchmark GMD event on the most conservative thermal models known to date. The revision was also based on input from transformer manufacturer and industry SMEs. The justification is documented in the thermal screening criterion white paper. 2B. The 75 A per phase criterion in Requirement R6 applies to transformer thermal impact assessment only. 3. The commenter's suggestion that the scaling factors do not agree by a factor of 22 with geoelectric fields in a cited paper is incorrect. Equation (2) from TPL-007 attachment 1 specifies a lower bound on the scaling factor. This lower bound scaling factor was not applied in the commenter's calculation resulting in a lower value for geoelectric field. 4. TPL-007 addresses impacts to the Bulk-Power System from GMD-related harmonics, which conforms to the scope of the standard as established in the Standard Authorization Request and FERC Order No. 779 (P. 2). Table 1 defines the planning event to include		

"Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event".		
South Carolina Electric & Gas	Yes	
Oncor Electric Delivery LLC	Yes	
South Carolina Electric & Gas	Yes	
Exelon and its Affiliates	Yes	
American Transmission Company	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
PacifiCorp		See response to #1.

END OF REPORT

Mark Olson

From:	Gale Nordling <gnordling@emprimus.com>
Sent:	Thursday, November 20, 2014 3:36 PM
To:	Mark Olson; Mark Lauby; Thomas Burgess; Mark Rossi; John Moura
Subject:	NERC Geomagnetic and Geoelectric Field Benchmark Model and Recommendations
Attachments:	Chinese paper on GIC Curents Liu et al 2014.pdf; GMD Correlated Equipment Insurance Claims.pdf; PESGM2013-000013_Generators.pdf; NERC Formula Compared to China Data rev 1.xlsx

New studies and papers bring significant clarity and information relevant to the proposed NERC GMD standards. Please accept the following comments for additional changes to NERC GMD Benchmark Model as recently revised:

1. We renew all previous comments and objections.

2. Changing transformer thermal screening criteria to 75 amps/phase from 15 amps/phase would not meet industry best practices for grid operation because:
   a. Some transformers have a GIC rating under 75 amps/phase
   b. The standard would suggest there is little or no damage to electrical equipment until you reach 75 amps/phase of GIC. The Luis Marti paper attached suggests rotor damage due to harmonics when GIC reaches levels of 50 or more amps/phase.

3. The NERC Benchmark formula modified further for latitude and soil does not give results that are anywhere near actual data. In fact a calculation that we have made (see attached Excel spreadsheet) for actual data recorded in China (see attached Chinese paper) would suggest the NERC Benchmark formula understates the actual geoelectric field by a <u>factor</u> of 22 (not 22%). For the Benchmark Model to be used to determine grid reliability and mitigation for public health and safety (and national security), the Benchmark Model must be consistent with actual data.

4. The Benchmark Model does very little to address harmonics and damage to both customer equipment and to utility equipment. Attached is a recent study done by Lockheed Martin, Zurich and NOAA in which claims for damage to customers were correlated to GMD events during the period of 2000-2010. The study shows in excess of $2 Billion of damage per year in the US due to low level solar storms (due to harmonics). The solar storms for this period are nowhere near in size to either the Carrington event or even the 1989 Quebec solar event. This would suggest that utilities on a regular year to year basis are in violation of IEEE 519 for both FERC approved wholesale contracts and for power delivered to customers. Customers on the distribution side are being damaged every year by harmonics. The NERC proposed standards don't address this virtually at all, and don't deal with either the ordinary year to year solar storms or the severe solar superstorms on the damage to customers and the violations of IEEE 519. This new study also found little or no difference in damage due to latitude which would suggest the NERC standard is wrong on latitude adjustments as well. Latitude adjustments must also be justified by actual data. This new study also changes the issue of harmonics from a low frequency (ie one in 50 or 100 year event) to an every year event which must be addressed for all levels of solar storm.

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RESEARCH ARTICLE OPEN ACCESS

Observations and modeling of GIC in the Chinese large-scale high-voltage power networks

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ABSTRACT

During geomagnetic storms, the geomagnetically induced currents (GIC) cause bias fluxes in transformers, resulting in half-cycle saturation. Severely distorted exciting currents, which contain significant amounts of harmonics, threaten the safe operation of equipment and even the whole power system. In this paper, we compare GIC data measured in transformer neutrals and magnetic recordings in China, and show that the GIC amplitudes can be quite large even in mid-low latitude areas. The GIC in the Chinese Northwest 750 kV Power Grid are modeled based on the plane wave assumption. The results show that GIC flowing in some transformers exceed 30 A/phase during strong geomagnetic storms. GIC are thus not only a high-latitude problem but networks in middle and low latitudes can be impacted as well, which needs careful attention.

Key words. electric circuit – geomagnetically induced currents (GIC) – modelling – engineering – space weather

1. Introduction

During strong space weather storms, which are caused by the activity of the Sun, the Earth's magnetic field is intensely disturbed by the space current system in the magnetosphere and ionosphere. The electric fields induced by time variations of the geomagnetic field drive geomagnetically induced currents (GIC) in electric power transmission networks. The frequencies of GIC are in the range of 0.0001 ~ 0.1 Hz. Such quasi-DC currents cause bias fluxes in transformers, which result in half-cycle saturation due to the nonlinear response of the core material (e.g., Kappenman & Albertson 1990; Molinski 2002; Kappenman 2007). The sharply increased magnetizing current with serious waveform distortion may lead to temperature rise and vibration in transformers, reactive power fluctuations, voltage sag, protection relay malfunction, and possibly even a collapse of the whole power system (e.g., Kappenman 1996; Bolduc 2002).

Large GIC are usually considered to occur at high latitudes such as North America and Scandinavia, where tripping problems and even blackouts of power systems due to GIC have been experienced (Bolduc 2002; Pulkkinen et al. 2005; Wik et al. 2009). Large currents in transformer neutrals have been monitored in the Chinese high-voltage power system many times during geomagnetic storms although China is a mid-low-latitude country. At the same time, transformers have had abnormal noise and vibration. Those events have been shown to be caused by GIC based on analyses of simultaneous magnetic data and GIC recordings (Liu & Xie 2005; Liu et al. 2009a). The power grids are using higher voltages, longer transmission distances, and larger capacity with the developing economy in China. So, the risk that the power systems would suffer from GIC problems may obviously increase. The Chinese Northwest 750 kV power grid has long transmission lines with small resistances making it prone to large GIC during geomagnetic storms. Thus it is important to model GIC particularly in that network.

2. GIC observations in Chinese high-voltage power grid

We acquire GIC data through the neutral point of the transformer at the Ling'ao nuclear power plant (22.6° N, 114.6° E) in the Guangdong Province. Besides, geomagnetic field data are collected from the Zhaoqing Geomagnetic Observatory (23.1° N, 112.3° E) which is not very far from Ling'ao. Figure1 shows the neutral point current (top panel), the horizontal component of the geomagnetic field (bottom panel), and its variation rate (middle panel) during the magnetic storms on 7–8 (a) and 9–10 (b) November 2004. The occurrence times of the current peaks match with those of the geomagnetic field variation rate. It is confirmed that there is no HVDC (high-voltage direct current) monopole operation during that time. So it is reasonable to believe that the currents are really GIC induced by geomagnetic storms. The maximum value of GIC is up to 75.5 A/3 phases, which is much higher than the DC bias caused by monopole operation of HVDC.

3. Modeling GIC in power grids

The modeling of GIC in a power grid can be divided into two steps (e.g., Pirjola 2000): step 1, calculating the geoelectric field induced by a magnetic storm; step 2, calculating the GIC in the power grid. The effect of the induced geoelectric field is equivalent to voltage sources in the transmission lines, which enables converting the GIC calculation into a circuit problem in step 2.

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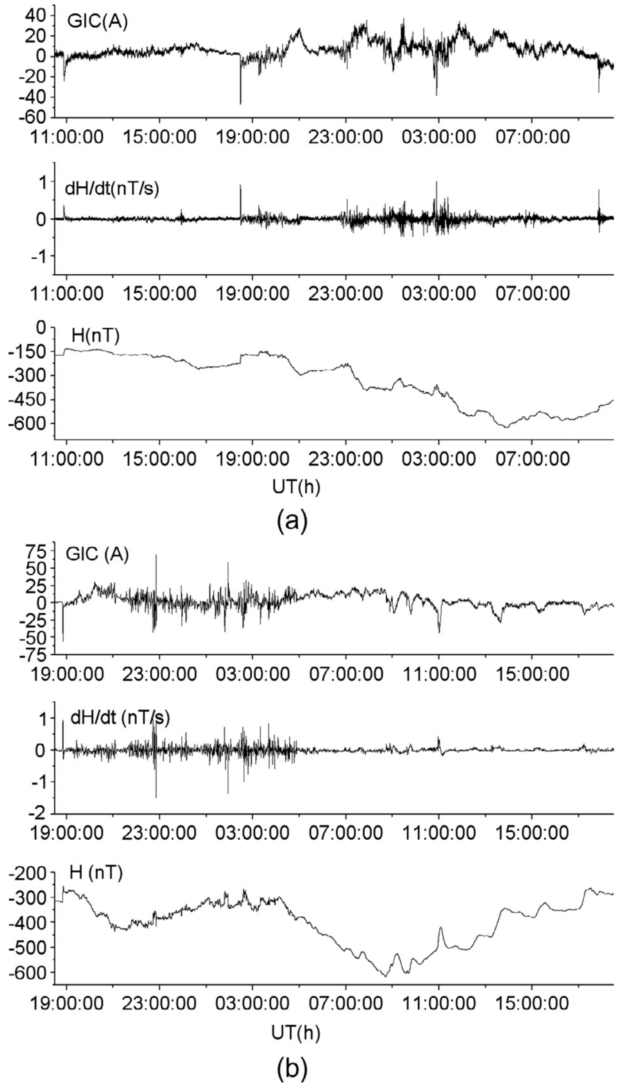


Fig. 1. GIC data at the Ling'ao nuclear power plant on 7–8 (a) and 9–10 (b) November 2004. The horizontal component of the geomagnetic field and its variation rate are also shown based on data from the Zhaoqing Geomagnetic Observatory.

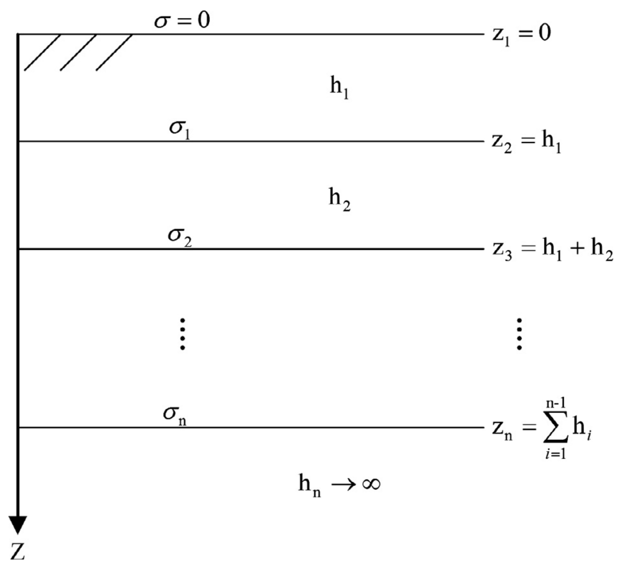


Fig. 2. Layered Earth model for calculating the induced geoelectric field.

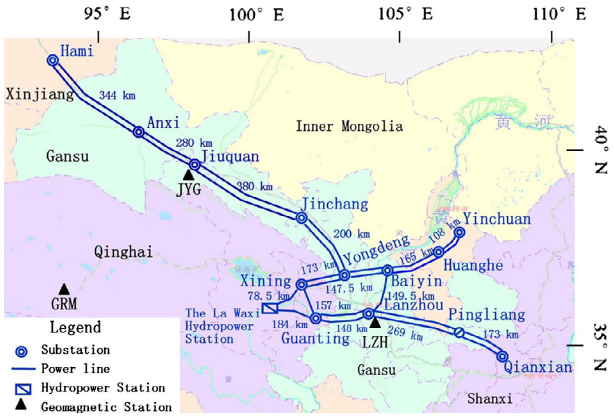


Fig. 3. Chinese Northwest 750 kV power grid. Three geomagnetic observatories (GRM, LZH, and JYG) are also shown on the map. (The WMQ observatory is not located in the area of this map.)

Table 1. Locations of geomagnetic observatories in the area of the Chinese Northwest 750 kV power grid.

Name	Longitude (°E)	Latitude (°N)
WMQ	87.7	43.8
GRM	94.9	36.4
LZH	103.8	36.1
JYG	98.2	39.8

3.1. Calculating the electric field using a layered earth model

We use the standard conventional Cartesian geomagnetic coordinate system in which the x, y and z axes point northwards, eastwards, and downwards, respectively. According to the plane wave assumption (e.g., Boteler 1999), the relation between perpendicular horizontal components of the geoelectric (E) and geomagnetic (B) fields at the earth's surface can be expressed as

$$E_x(\omega) = \frac{1}{\mu_0} B_y(\omega) Z(\omega), \tag{1}$$

$$E_y(\omega) = -\frac{1}{\mu_0} B_x(\omega) Z(\omega), \tag{2}$$

where μ_0 is the vacuum permeability and Z is surface impedance of the earth which depends on the conductivity structure of the earth and on the angular frequency ω.

In a previous study about GIC in China, Liu et al. (2009b) used a uniform half-space model for the earth. However, one-dimensional layered earth models are more accurate descriptions for the real situations. Figure 2 shows a layered earth model which contains n layers with conductivities σ_1, σ_2, …, σ_n and thicknesses h_1, h_2, …, $h_n \to \infty$.

The thickness of the bottom layer is $h_n \to \infty$, and $E_x = 0$ and $B_y = 0$ when $z \to \infty$. Hence the impedance at the top of the layer of the nth layer is

$$Z_n = \mu_0 \frac{E_x}{B_y} = \frac{j\omega\mu_0}{k_n} = \sqrt{\frac{j\omega\mu_0}{\sigma_n}}, \tag{3}$$

where k_n is the propagation constant given by $k_n = \sqrt{j\omega\mu_0\sigma_n}$. The impedance at the top of the layer within the mth layer ($m = 1, 2, \ldots, n-1$) can be expressed as

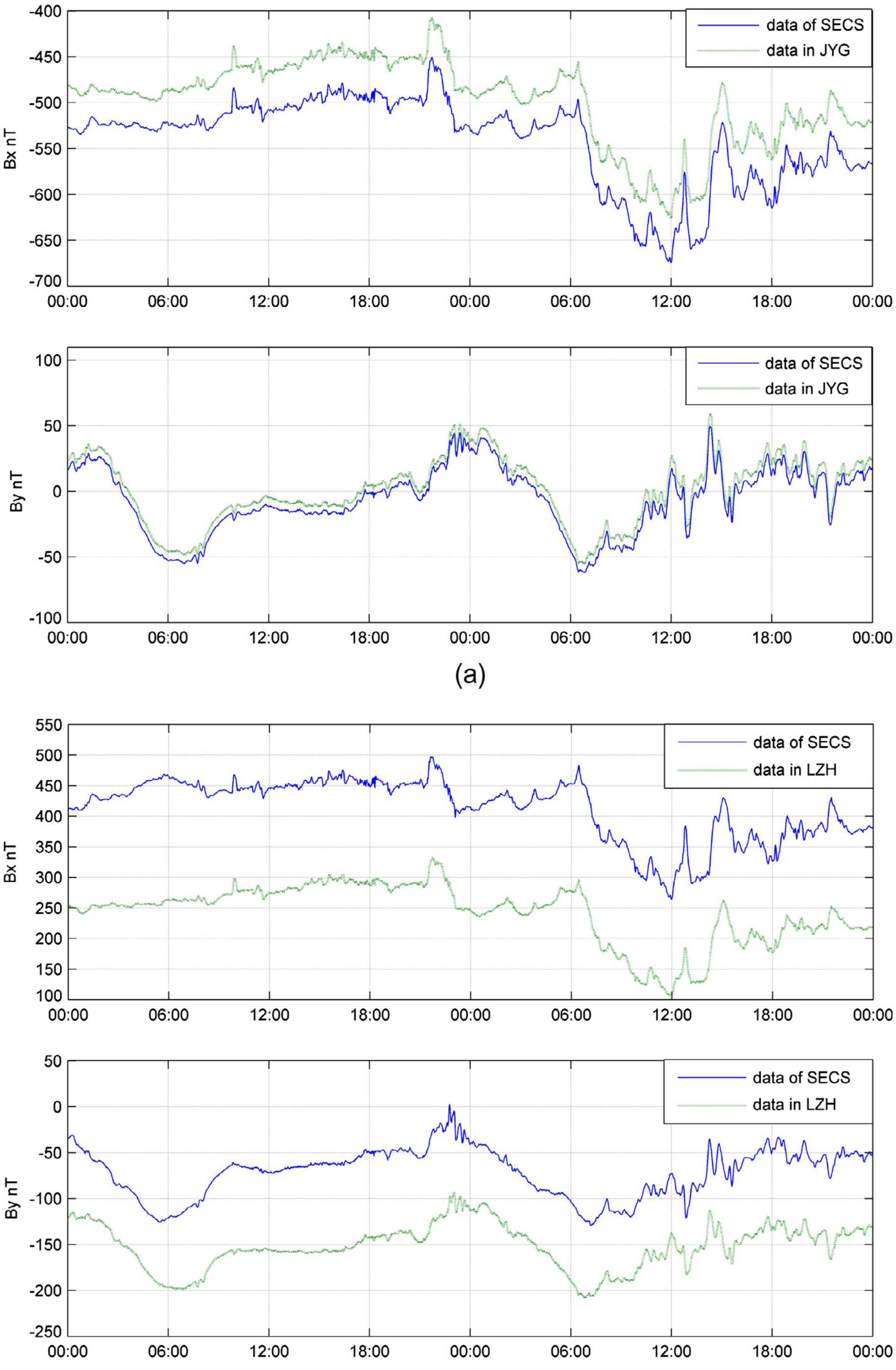


Fig. 4. Measured magnetic data and the SECS-derived magnetic data on 29–30 May 2005. The horizontal axis is the UT time in hours (a) magnetic data from JYG observatory and the SECS-derived magnetic data for Jiuquan substation and (b) magnetic data from LZH observatory and the SECS-derived magnetic data for Yongdeng substation.

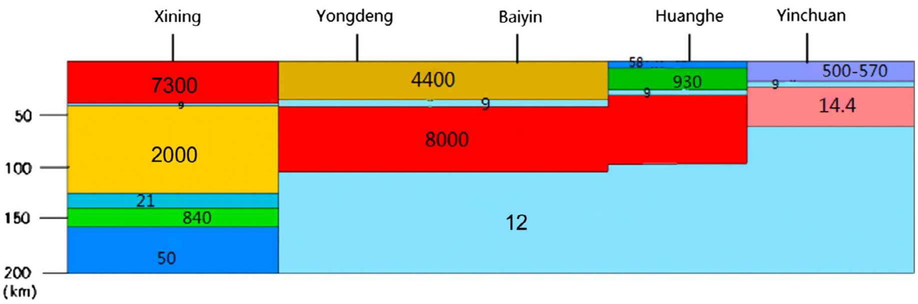


Fig. 5. Resistivity for the section Xining-Yinchuan along 750 kV power transmission lines.

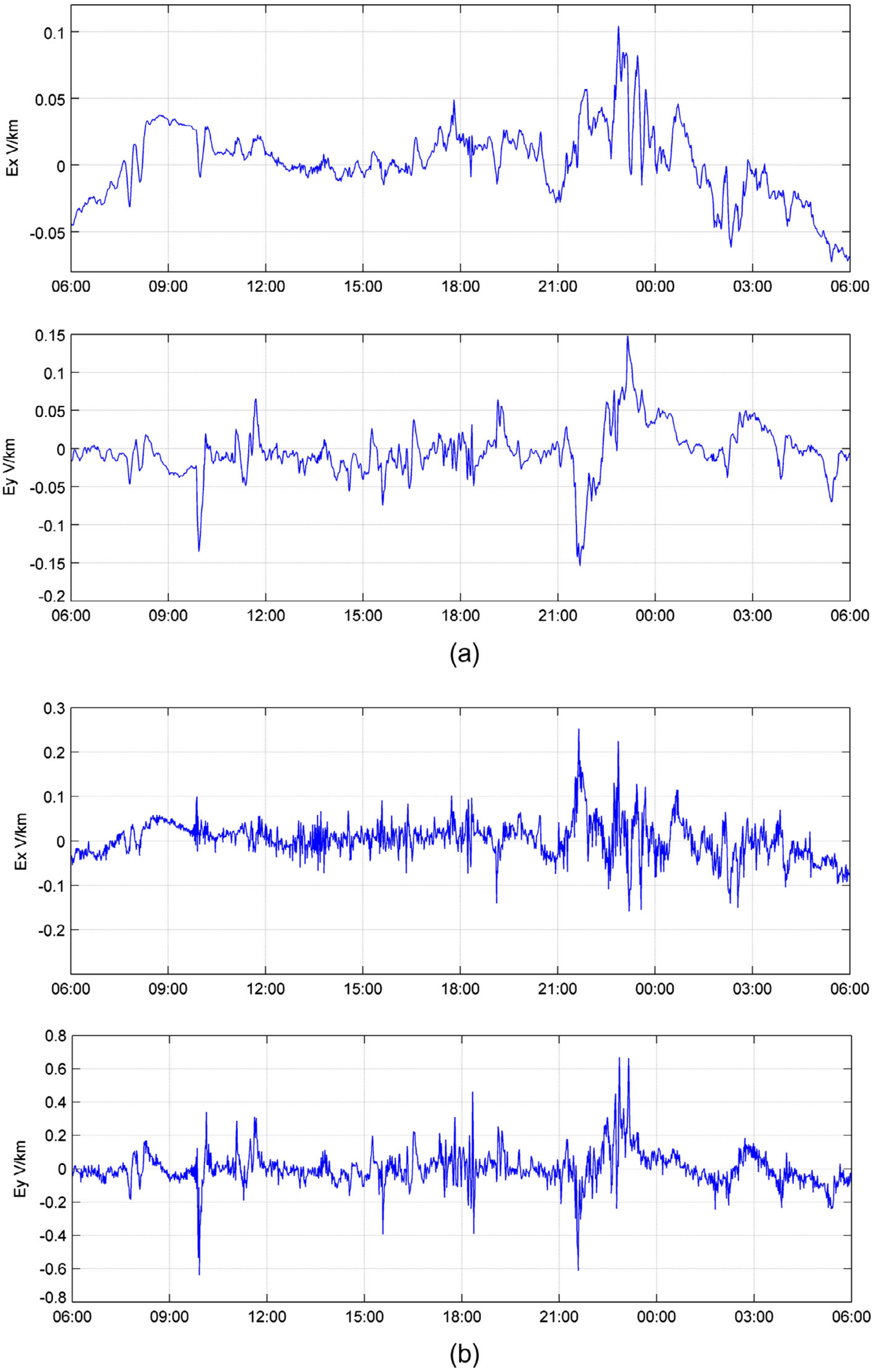


Fig. 6. Calculated geoelectric fields at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) E-Jiuquan and (b) E-Yongdeng.

$$Z_m = Z_{0m}\frac{1 - L_{m+1}e^{-2k_m h_m}}{1 + L_{m+1}e^{-2k_m h_m}} \tag{4}$$

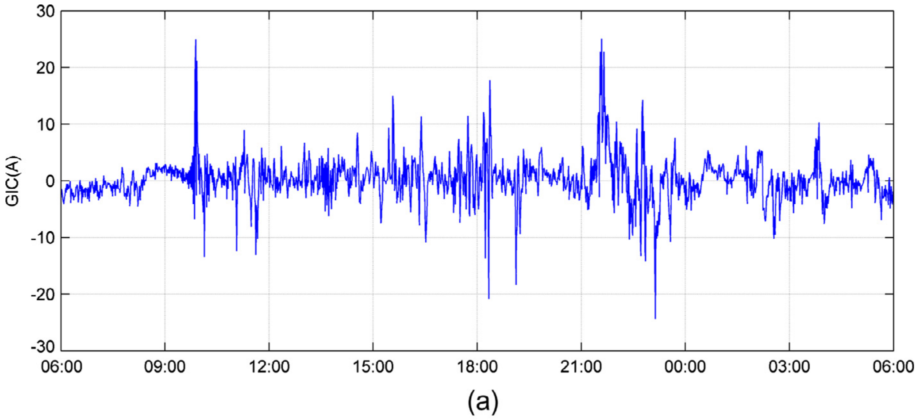
where $k_m = \sqrt{j\omega\mu_0\sigma_m}$ and $Z_{0m} = \frac{jw\mu_0}{k_m}$ and $L_{m+1} = \frac{Z_{0m}-Z_{m+1}}{Z_{0m}+Z_{m+1}}$.

In the model, the bottom of mth layer is the top of $(m + 1)$th layer, so equation (4) can be seen as a recursive formula for the impedance at the top of each layer, through which we can calculate the surface impedance of the Earth Z. The geoelectric field in frequency domain can be calculated from geomagnetic data according to equations (1) and (2). Then the result has to be inverse Fourier transformed back to the time domain.

3.2. Calculating GIC

The frequencies of GIC are very low from the view point of power systems. Thus the GIC can be treated as a direct current. The effect of the geoelectric field on a power grid is equivalent to a set of voltage sources in the transmission lines between the substations. The value of the voltage is the integral of the electric field along the line, i.e.:

$$V_{AB} = \int_A^B \vec{E} \cdot \overleftarrow{dl}\,. \tag{5}$$



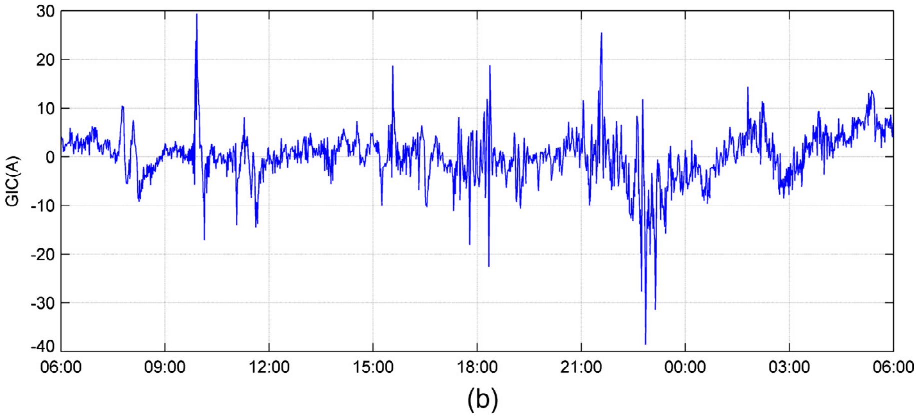


Fig. 7. Calculated GIC at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) calculated GIC at Jiuquan substation and (b) calculated GIC at Youngdeng substation.

If the geoelectric field is uniform, the integrals are independent of the paths. Therefore equation (5) can be simplified to

$$V_{AB} = L_{AB}(E_x \sin\theta + E_y \cos\theta) \tag{6}$$

Where L_{AB} is the direct distance between nodes A and B; θ is the "compass angles" i.e. clockwise from geographic North.

The GIC flowing from the power grid to the earth can be expressed as a column matrix $\mathbf{I}$, which has the following formula (e.g., Pirjola & Lehtinen 1985)

$$\mathbf{I} = (\mathbf{1} + \mathbf{YZ})^{-1}\mathbf{J}, \tag{7}$$

where $\mathbf{1}$ is a unit (identity) matrix; $\mathbf{Y}$ and $\mathbf{Z}$ are the network admittance matrix and the earthing impedance matrix respectively. The elements of column matrix $\mathbf{J}$ are defined by

$$J_i = \sum_{j=1, j\neq i}^{N} \frac{V_{ij}}{R_{ij}}. \tag{8}$$

The matrix $\mathbf{J}$ gives the GIC between the power grid and the earth in the case of ideal groundings, i.e. the grounding resistances are zero making $\mathbf{Z}$ a zero matrix.

4. Modeling GIC in Chinese Northwest 750 kV power grid

The problem of GIC should be considered more serious in the Chinese Northwest 750 kV power grid because of the high voltage implying low transmission line resistances and because of the low earth conductivity increasing geoelectric field values. The power grid (shown in Fig. 3) for which GIC calculations are made in this paper is mainly located in the Gansu Province in the Northwest of China. We ignore the lower voltage part connected to the 750 kV power grid when modeling the GIC, because the resistances of that part are much larger, and so it is considered to have little influence on GIC flowing in the 750 kV system.

4.1. Geoelectric field calculation

We use data of the geomagnetic storm on 29–30 May 2005. The power grid is very large, extending more than 2 000 km in an east-west direction and 1 500 km in a North-South direction, so the geomagnetic variations cannot be considered to be the same all over the network. The magnetic data from four geomagnetic observatories, whose locations are shown in Figure 3 and in Table 1, are used to calculate the geoelectric field. The local magnetic data are interpolated by using the spherical elementary current systems (SECS) method (Amm 1997). The method uses geomagnetic field data to inverse the ionosphere equivalent current according to which the geomagnetic field data of every location can be calculated. Therefore the interpolation of magnetic data at different locations during a storm can be acquired. As examples, Figure 4a shows the measured data from JYG and the SECS-derived magnetic data for Jiuquan Substation, and Figure 4b shows the measured data from LZH and the SECS-derived magnetic data for Yongdeng Substation on 29–30 May 2005. It can be seen that the differences between measured magnetic data and the SECS-derived

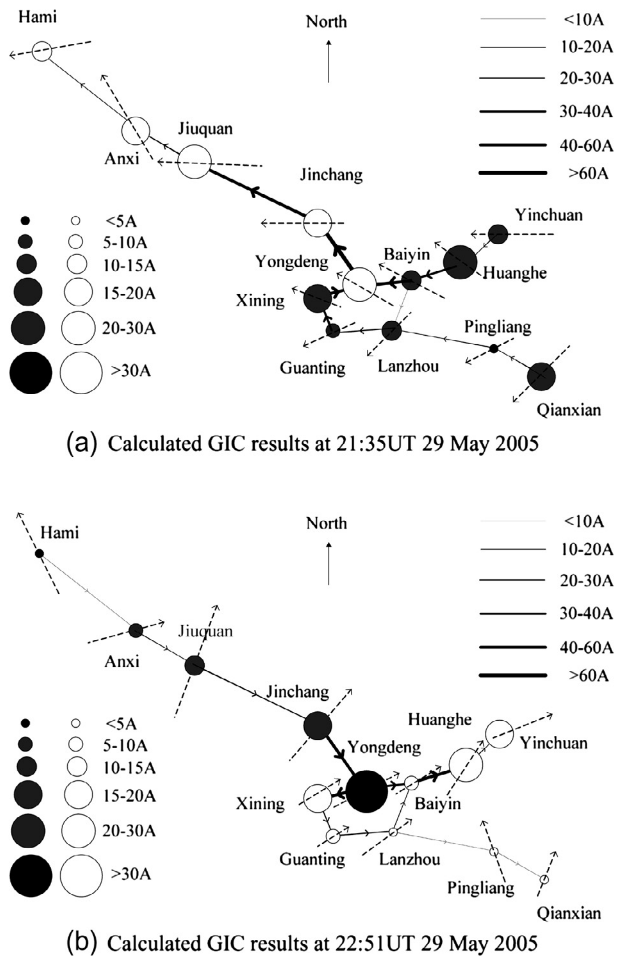


Fig. 8. Snapshots at 21:35 on 29 May 2005 (a) and at 22:51UT on 29 May 2005 (b) of calculated GIC at different sites of the Chinese Northwest 750 kV power grid. The solid circle represents that the GIC flow into the power network from ground, the hollow one means that GIC flow into the ground. The dashed line with an arrow represents the direction of electric field at that substation.

data are little except for the base line values which have no effect on the induced electric fields.

The earth conductivities are quite different across the power grid considered, so the geoelectric field values are calculated segment by segment according to the local magnetic data and the local layered earth model. In other words, we utilize the piecewise layered earth model. The earth resistivity in the region where the Chinese Northwest 750 kV power grid is located was provided by Prof. Liu Guo-Xing, a geologist at the Jilin University (private communication). Figure 5 shows a section of the earth resistivity in Ω·m from Xining to Yinchuan along the 750 kV power lines (see Fig. 3). The resistances of some places are given within a range such as 500–570 at Yinchuan in Figure 5. The upper limit values were used to calculate the induced electric fields because they stand for the most disadvantageous situation to the power grid.

As mentioned, the geoelectric fields have been calculated all over the Chinese Northwest 750 kV system based on the Piecewise layered earth models during the geomagnetic storm on 29–30 May 2005. As examples, Figure 6 shows the geoelectric field at Jiuquan and Yongdeng (whose locations are shown in Fig. 3). Our calculation results indicate that the largest E_x value is 0.36 V/km and the largest E_y value is 0.668 V/km in the area of the Northwest 750 kV grid during the geomagnetic storm considered. It is also shown by Figure 6 that the electric fields calculated for Yongdeng and Jiugan are quite different because the Earth conductivity at Yongdeng is much lower than that at Jiuquan.

4.2. GIC calculation

The GIC through all neutral points of the transformers to the Earth and in all transmission lines of the Chinese Northwest 750 kV network have been calculated. Figure 7 shows the GIC through two typical substations: Jiuquan and Yondeng (also referred to in Fig. 6). The largest GIC at Jiuquan is 25.08 A/phase at 21:35 UT on 29 May 2005, and the largest GIC at Yongdeng is 38.63 A/phase at 22:51 UT on 29 May 2005.

As snapshots, Figure 8 shows the GIC through every node and line at 21:35 UT (panel a) and at 22:51UT (panel b) on 29 May 2005 when the GIC through some of the nodes reach their peaks. It can be seen that the largest GIC through a neutral point is 38.63 A/phase, which is obtained at theYongdeng substation at 22:51 as already mentioned above (see also Fig. 7). The peak GIC through a transmission line is 68.84 A/phase, which occurs in the line from Yongdeng to Jinchang at 21:35 UT. It should be note that there is one single-phase transformer bank in a 750 kV substation except Guanting and Yinchuan where the number of transformer banks is two.

5. Conclusions

The high-voltage power grid in China may experience large GIC during geomagnetic storms, which has been concluded from monitoring the current through the neutral point at Ling'ao nuclear power plant. The GIC in the Chinese Northwest 750 kV power grid during a specific geomagnetic storm have been modeled based on calculating the geoelectric field using the piecewise layered earth models. It can be seen from the results that some sites are sensitive to geomagnetic storms, and the magnitude of GIC can be quite large (> 30 A/phase) during strong geomagnetic storms. Our studies thus clearly demonstrate that GIC are not only a high-latitude problem but networks in middle and low latitudes can be impacted as well. Factors increasing GIC risks in China include the large size of the power network, the small resistances of the transmission lines, and the high resistivity of the earth.

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Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment

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Abstract. Geomagnetically induced currents are known to induce disturbances in the electric power grid. Here, we perform a statistical analysis of 11,242 insurance claims from 2000 through 2010 for equipment losses and related business interruptions in North-American commercial organizations that are associated with damage to, or malfunction of, electrical and electronic equipment. We find that claims rates are elevated on days with elevated geomagnetic activity by approximately 20% for the top 5%, and by about 10% for the top third of most active days ranked by daily maximum variability of the geomagnetic field. When focusing on the claims explicitly attributed to electrical surges (amounting to more than half the total sample), we find that the dependence of claims rates on geomagnetic activity mirrors that of major disturbances in the U.S. high-voltage electric power grid. The claims statistics thus reveal that large-scale geomagnetic variability couples into the low-voltage power distribution network and that related power-quality variations can cause malfunctions and failures in electrical and electronic devices that, in turn, lead to an estimated 500 claims per average year within North America. We discuss the possible magnitude of the full economic impact associated with quality variations in electrical power associated with space weather.

1. Introduction

Large explosions that expel hot, magnetized gases on the Sun can, should they eventually envelop Earth, effect severe disturbances in the geomagnetic field. These, in turn, cause geomagnetically induced currents (GICs) to run through the surface layers of the Earth and through conducting infrastructures in and on these, including the electrical power grids. The storm-related GICs run on a background of daily variations associated with solar (X)(E)UV irradiation that itself is variable through its dependence on both quiescent and flaring processes.

The strongest GIC events are known to have impacted the power grid on occasion [see, e.g., *Kappenman et al.*, 1997; *Boteler et al.*, 1998; *Arslan Erinmez et al.*, 2002; *Kappenman*, 2005; *Wik et al.*, 2009]. Among the best-known of such impacts is the 1989 Hydro-Québec blackout [e.g., *Bolduc*, 2002; *Béland and Small*, 2004]. Impacts are likely strongest at mid to high geomagnetic latitudes, but low-latitude regions also appear susceptible [*Gaunt*, 2013].

The potential for severe impacts on the high-voltage power grid and thereby on society that depends on it has been assessed in studies by government, academic, and insurance industry working groups [e.g., *Space Studies Board*, 2008; *FEMA*, 2010; *Kappenman*, 2010; *Hapgood*, 2011; *JASON*, 2011]. How costly such potential major grid failures would be remains to be determined, but impacts of many billions of dollars have been suggested [e.g., *Space Studies Board*, 2008; *JASON*, 2011].

Non-catastrophic GIC effects on the high-voltage electrical grid percolate into financial consequences for the power market [*Forbes and St. Cyr*, 2004, 2008, 2010] leading to price variations on the bulk electrical power market on the order of a few percent [*Forbes and St. Cyr*, 2004].

Schrijver and Mitchell [2013] quantified the susceptibility of the U.S. high-voltage power grid to severe, yet not extreme, space storms, leading to power outages and power-quality variations related to voltage sags and frequency changes. They find, "with more than 3σ significance, that approximately 4% of the disturbances in the US power grid reported to the US Department of Energy are attributable to strong geomagnetic activity and its associated geomagnetically induced currents."

The effects of GICs on the high-voltage power grid can, in turn, affect the low-voltage distribution networks and, in principle, might impact electrical and electronic systems of users of those regional and local networks. A first indication that this does indeed happen was reported on in association with tests conducted by the Idaho National Laboratory (INL) and the Defense Threat Reduction Agency (DTRA). They reported [*Wise and Benjamin*, 2013] that "INL and DTRA used the lab's unique power grid and a pair of 138kV core form, 2 winding substation transformers, which had been in-service at INL since the 1950s, to perform the first full-scale testing to replicate conditions electric utilities could experience from geomagnetic disturbances." In these experiments, the researchers could study how the artificial GIC-like currents resulted in harmonics on the power lines that can affect the power transmission and distribution equipment. These "tests demonstrated that geomagnetic-induced harmonics are strong enough to penetrate many power line filters and cause temporary resets to computer power supplies and disruption to electronic equipment, such as uninterruptible power supplies".

In parallel to that experiment, we collected information on insurance claims submitted to Zurich North-America (NA) for damage to, or outages of, electrical and electronic systems from all types of industries for a comparison with geomagnetic variability. Here, we report on the results of a retrospective cohort exposure analysis of the impact of geomagnetic variability on the frequency of insurance claims. In this analysis, we contrast insurance claims frequencies on "high-exposure" dates (i.e., dates of high geomagnetic activity) with a control sample of "low-exposure" dates (i.e., dates with essentially quiescent space weather conditions), carefully matching each high-exposure date to a

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control sample nearby in time so that we may assume no systematic changes in conditions other than space weather occurred between the exposure dates and their controls (thus compensating for seasonal weather changes and other trends and cycles).

For comparison purposes we repeat the analysis of the frequency of disturbances in the high-voltage electrical power grid as performed by *Schrijver and Mitchell* [2013] for the same date range and with matching criteria for threshold setting and for the selection of the control samples. In Section 1 we describe the insurance claim data, the metric of geomagnetic variability used, and the grid-disturbance information. The procedure to test for any impacts of space weather on insurance claims and the high-voltage power grid is presented and applied in Section 3. We summarize our conclusions in Section 4 where we also discuss the challenges in translating the statistics on claims and disturbances into an economic impact.

2. Data

2.1. Insurance claim data

We compiled a list of all insurance claims filed by commercial organizations to Zurich NA relating to costs incurred for electrical and electronic systems for the 11-year interval from 2000/01/01 through 2010/12/31. Available for our study were the date of the event to which the claim referred, the state or province within which the event occurred, a brief description of the affected equipment, and a top-level assessment of the probable cause. Information that might lead to identification of the insured parties was not disclosed.

Zurich NA estimates that it has a market share of approximately 8% in North America for policies covering commercially-used electrical and electronic equipment and contingency business interruptions related to their failure to function properly during the study period. Using that information as a multiplier suggests that overall some 12,800 claims are filed per average year related to electrical/electronic equipment problems in North-American businesses. The data available for this study cannot reveal impacts on uninsured or self-insured organizations or impacts in events of which the costs fall below the policy deductable.

The 11-year period under study has the same duration as that characteristic of the solar magnetic activity cycle. Fig. 1 shows that the start of this period coincides with the maximum in the annual sunspot number for 2000, followed by a decline into an extended minimum period in 2008 and 2009, ending with the rise of sunspot number into the start of the next cycle.

The full sample of claims, regardless of attribution, for which an electrical or electronic system was involved includes 11,242 entries. We refer to this complete set as set A.

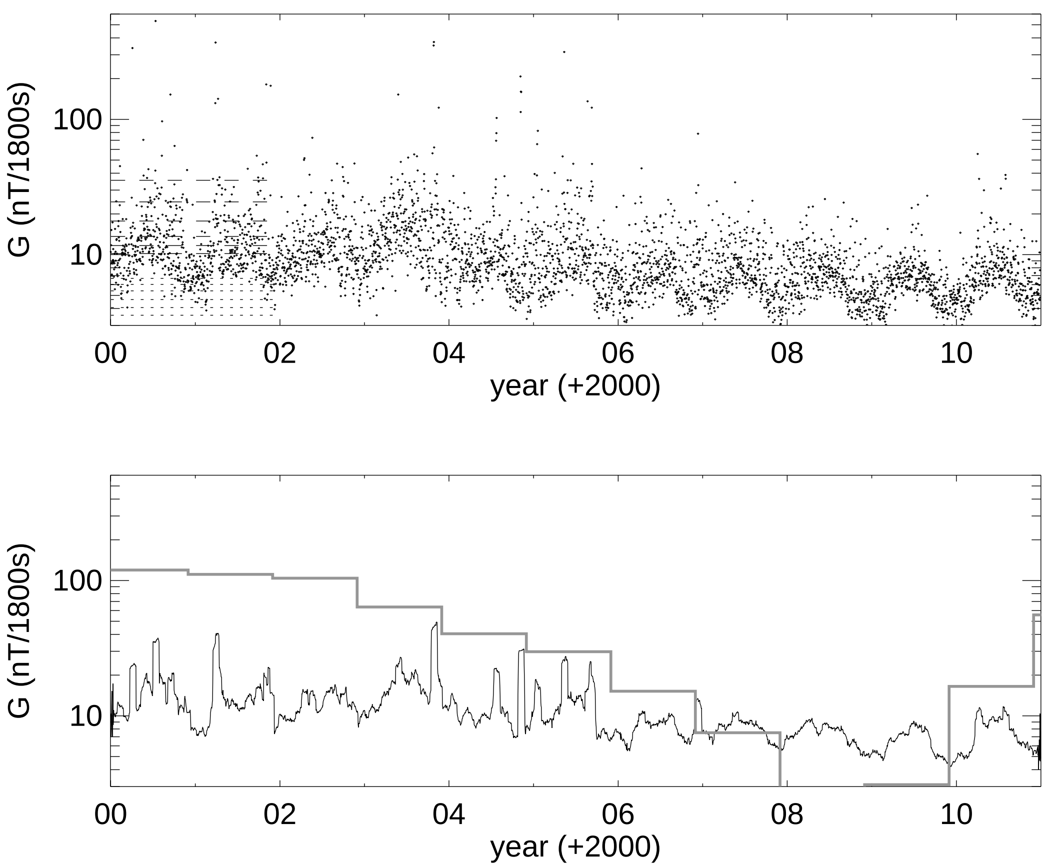

Figure 1. *Daily values $G \equiv max(|dB/dt|)$ based on 30-min. intervals (dots; nT/1800s) characterizing geomagnetic variability for the contiguous United States versus time (in years since 2000). The 27-d running mean is shown by the solid line. The levels for the 98, 95, 90, 82, 75, and 67 percentiles of the entire sample are shown by dashed lines (sorting downward from the top value of G) and dotted lines (sorting upward from the minimum value of the daily geomagnetic variability as expressed by $G \equiv max(|dB/dt|)$). The grey histogram shows the annual mean sunspot number.*

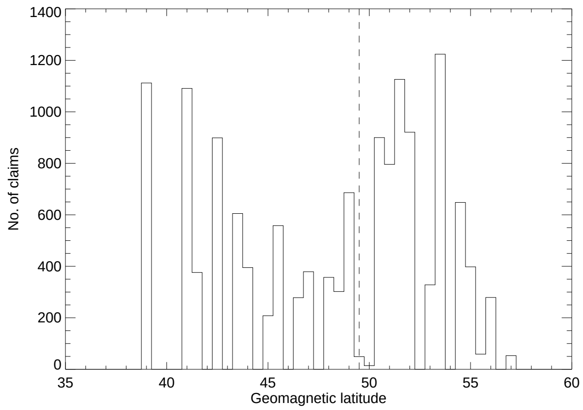

Figure 2. *Number of insurance claims sorted by geomagnetic latitude (using the central geographical location of the state) in 0.5° bins. The dashed line at 49.5° is near the median geomagnetic latitude of the sample (at 49.3°), separating what this paper refers to as high-latitude from low-latitude states.*

Claims that were attributed to causes that were in all likelihood not associated with space weather phenomena were deleted from set A to form set B (with 8,151 entries remaining after review of the Accident Narrative description of each line item). Such omitted claims included attributions to water leaks and flooding, stolen or lost equipment, vandalism or other intentional damage, vehicle damage or vehicular accidents, animal intrusions (raccoons, squirrels, birds, etc.), obvious mechanical damage, and obvious weather damage (ice storm damage, hurricane/windstorm damage, etc.). The probable causes for the events making up set B were limited to the following categories (sorted by the occurrence frequency, given in percent): Misc: Electrical surge (59%); Apparatus, Miscellaneous Electrical - Breaking (30%); Apparatus, Miscellaneous Electrical - Arcing (4.1%); Electronics - Breaking (1.6%); Apparatus, Miscellaneous Electrical - Overheating (1.4%); Transformers - Arcing (0.9%); Electronics - Arcing (0.6%); Transformers - Breaking (0.5%); Generators - Breaking (0.4%); Apparatus, Electronics - Overheating (0.3%); Generators - Arcing (0.2%); Generators - Overheating (0.2%); and Transformers - Overheating (0.1%).

Fig. 2 shows the number of claims received as a function of the mean geomagnetic latitude for the state within which the claim was recorded. Based on this histogram, we divided the claims into categories of comparable size for high and low geomagnetic latitudes along a separation at 49.°5 north geomagnetic latitude to enable testing for a dependence on proximity to the auroral zones. We note that we do not have access to information about the latitudinal distribution of insured assets, only on the claims received. Hence, we can only assess any dependence of insurance claims on latitude in a relative sense, comparing excess relative claims frequencies for claims above and below the median geomagnetic latitudes, as discussed in Sect. 3.

2.2. Geomagnetic data

Geomagnetically-induced currents are driven by changes in the geomagnetic field. These changes are caused by the interaction of the variable, magnetized solar wind with the geomagnetic field and by the insolation of Earth's atmosphere that varies globally with solar activity and locally owing to the Earth's daily rotation and annual revolution in its orbit around the Sun. A variety of geomagnetic activity indices is available to characterize geomagnetic field variability [e.g., *Jursa*, 1985]. These indices are sensitive to different aspects of the variable geomagnetic-ionospheric current systems as they may differentially filter or weight storm-time variations (Dst), disturbance-daily variations (Ds), or solar quiet daily variations (known as the Sq field), and may weight differentially by (geomagnetic) latitude. Here, we are interested not in any particular driver of

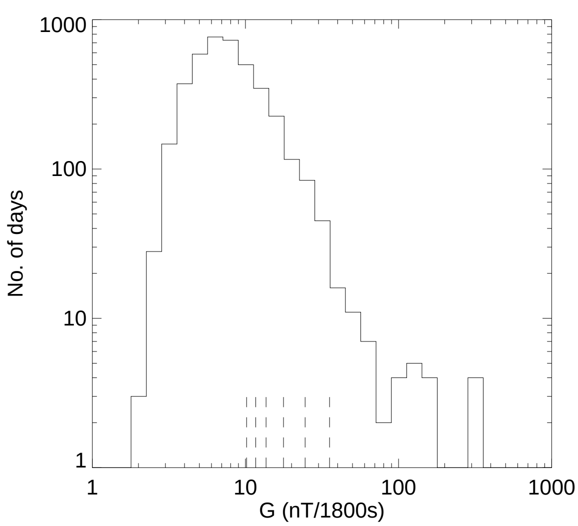

Figure 3. *Histogram of the number of days between 2000/01/01 and 2010/12/31 with values of $G \equiv max(|dB/dt|)$ in logarithmically spaced intervals as shown on the horizontal axis. The 98, 95, 90, 82, 75, and 67 percentiles (ranking G from low to high) are shown by dashed lines.*

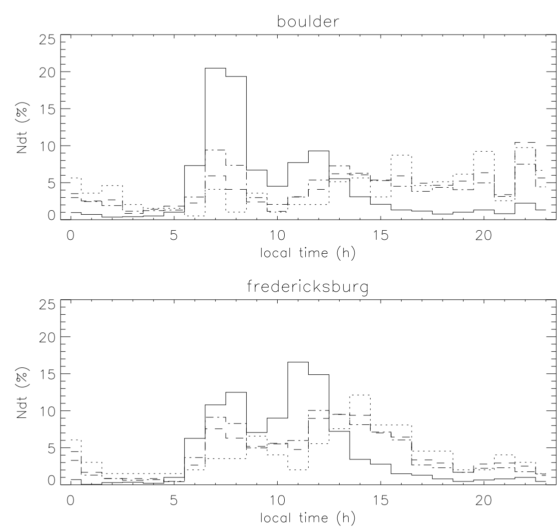

Figure 4. *Normalized histograms of the local times for which the values of $G \equiv max(|dB/dt|)$ reach their daily maximum (top: Boulder; bottom: Fredericksburg). The solid histogram shows the distribution for daily peaks for all dates with G values in the lower half of the distribution, i.e., for generally quiescent conditions. The dotted, dashed, and dashed-dotted histograms show the distributions for dates with high G values, for thresholds set at the 95, 82, and 67 percentiles of the set of values for G, respectively.*

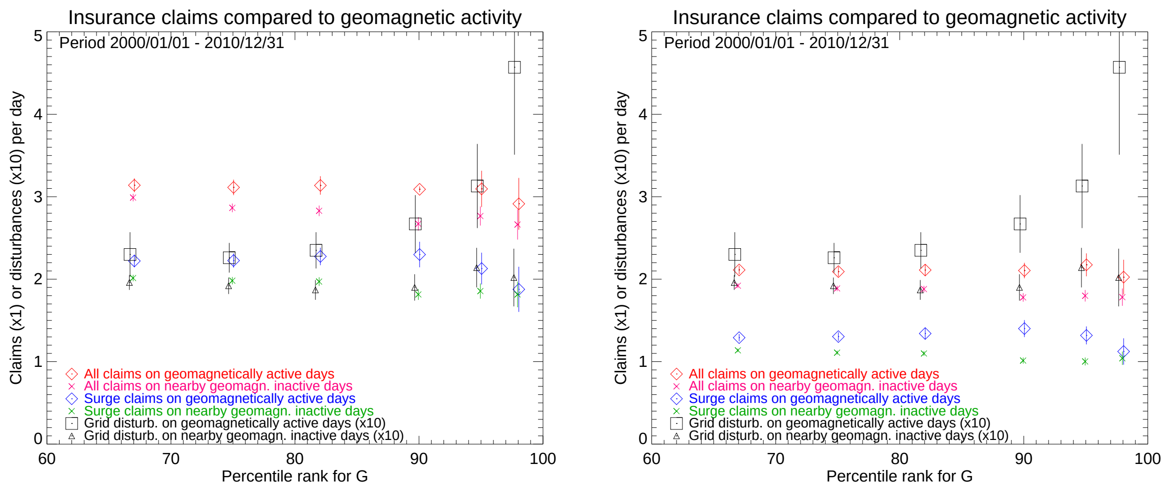

Figure 5. *Claims per day for the full sample of insurance claims (set* A *left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). Each panel shows mean incident claim frequencies* $n_i \pm \sigma_c$ *(diamonds) for the most geomagnetically active dates, specifically for the 98, 95, 90, 82, 75, and 67 percentiles of the distribution of daily values of* $G \equiv max(|dB/dt|)$ *sorted from low to high (shown with slight horizontal offsets to avoid overlap in the symbols and bars showing the standard deviations for the mean values). The asterisks show the associated claim frequencies* $n_c \pm \sigma_c$*, for the control samples. The panels also show the frequencies of reported high-voltage power-grid disturbances (diamonds and triangles for geomagnetically active dates and for control dates, respectively), multiplied by 10 for easier comparison, using the same exposure-control sampling and applied to the same date range as that used for the insurance claims.*

changes in the geomagnetic field but rather need a metric of the rate of change in the strength of the surface magnetic field as that is the primary driver of geomagnetically-induced currents.

To quantify the variability in the geomagnetic field we use the same metric as *Schrijver and Mitchell* [2013] based on the minute-by-minute geomagnetic field measurements from the Boulder (BOU) and Fredericksburg (FRD) stations (available via http://ottawa.intermagnet.org): we use these measurements to compute the daily maximum value, G, of $|dB/dt|$ over 30-min. intervals, using the mean value for the two stations. We selected this metric recognizing a need to use a more regional metric than the often-used global metrics, but also recognizing that the available geomagnetic and insurance claims data have poor geographical resolution so that a focus on a metric responsive to relatively low-order geomagnetic variability was appropriate. We chose a time base short enough to be sensitive to rapid changes in the geomagnetic field, but long enough that it is also sensitive to sustained changes over the course of over some tens of minutes. For the purpose of this study, we chose to use a single metric of geomagnetic variability, but with the conclusion of our pilot study revealing a dependence of damage to electrical and electronic equipment on space weather conditions, a multi-parameter follow up study is clearly warranted, ideally also with more information on insurance claims, than could be achieved with what we have access to for this exploratory study.

The BOU and FRD stations are located along the central latitudinal axis of the U.S.. The averaging of their measurements somewhat emphasizes the eastern U.S. as do the grid and population that uses that. Because the insurance claims use dates based on local time we compute the daily G values based on date boundaries of U.S. central time. Fig. 3 shows the distribution of values of G, while also showing the levels of the percentiles for the rank-sorted value of G used as threshold values for a series of sub-samples in the following sections.

Figure 4 shows the local times at which the maximum variations in the geomagnetic field occur during 30-min. intervals. The most pronounced peak in the distribution for geomagnetically quiet days (solid histogram) occurs around $7-8$ o'clock local time, i.e., a few hours after sunrise, and a second peak occurs around local noon. The histograms for the subsets of geomagnetically active days for which G values exceed thresholds set at 67, 82, and 95 percentiles of the sample are much broader, even more so for the Boulder station than for the Fredericksburg station. From the perspective of the present study, it is important to note that the majority of the peak times for our metric of geomagnetic variability occurs within the economically most active window from 7 to 18 hours local time; for example, at the 82-percentile of geomagnetic variability in G, 54% and 77% of the peak variability occur in that time span for Boulder and Fredericksburg, respectively.

From a general physics perspective, we note that periods of markedly enhanced geomagnetic activity ride on top of a daily background variation of the ionospheric current systes (largely associated with the "solar quiet" modulations, referred to as the Sq field) that is induced to a large extent by solar irradiation of the atmosphere of the rotating Earth, including the variable coronal components associated with active-region gradual evolution and impulsive solar flaring. We do not attempt to separate the impacts of these drivers in this study, both because we do not have information on the local times for which the problems occurred that lead to the insurance claims, and because the power grid is sensitive to the total variability in the geomagnetic field regardless of cause.

The daily G values are shown versus time in Fig. 1, along with a 27-d running mean and (as a grey histogram) the yearly sunspot number. As expected, the G value shows strong upward excursions particularly during the sunspot maximum. Note the annual modulation in G with generally lower values in the northern-hemispheric winter months than in the summer months.

2.3. Power-grid disturbances

In parallel to the analysis of the insurance claims statistics, we also analyze the frequencies of disturbances in the U.S. high-voltage power grid. *Schrijver and Mitchell* [2013] compiled a list of "system disturbances" published by the North American Electric Reliability Corporation (NERC: available since 1992) and by the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE; available since 2000). This information is compiled by NERC for a region with over 300 million electric power customers throughout the U.S.A. and in Ontario and New Brunswick in Canada, connected by more than 340,000 km of high-voltage transmission lines delivering power generated in some 18,000 power plants within the U.S. [*JASON*, 2011]. The reported disturbances include, among others, "electric service interruptions, voltage reductions, acts of sabotage, unusual occurrences that can affect the reliability of the bulk electric systems, and fuel problems." We use the complete set of disturbances reported from 2000/01/01 through 2010/12/31 regardless of attributed cause. We refer to *Schrijver and Mitchell* [2013] for more details.

3. Testing for the impact of space weather

In order to quantify effects of geomagnetic variability on the frequency of insurance claims filed for electrical and electronic equipment we need to carefully control for a multitude of variables that include trends in solar activity, the structure and operation of the power grid (including, for example, scheduled maintenance and inspection), various societal and technological factors changing over the years, as well as the costs and procedures related to the insurance industry, and, of course, weather and seasonal trends related to the insolation angle and the varying tilt of the Earth's magnetic field relative to the incoming solar wind throughout the year.

There are many parameters that may influence the ionospheric current systems, the quality and continuity of electrical power, and the malfunctioning of equipment running on electrical power. We may not presume that we could identify and obtain all such parameters, or that all power grid segments and all equipment would respond similarly to changes in these parameters. We therefore do not attempt a multi-parameter correlation study, but instead apply a retrospective cohort exposure study with tightly matched controls very similar to that applied by Schrijver and Mitchell (2013).

This type of exposure study is based on pairing dates of exposure, i.e., of elevated geomagnetic activity, with control dates of low geomagnetic activity shortly before or after each of the dates of exposure, selected from within a fairly narrow window in time during which we expect no substantial systematic variation in ionospheric conditions, weather, the operations of the grid, or the equipment powered by the grid. Our results are based on a comparison of claims counts on exposure dates relative to claims counts on matching sets of nearby control dates. This minimizes the impacts of trends (including "confounders") in any of the potential factors that affect the claims statistics or geomagnetic variability, including the daily variations in quiet-Sun irradiance and the seasonal variations as Earth orbits the Sun, the solar cycle, and the structure and operation of the electrical power network. This is a standard method as used in, e.g., epidemiology. We refer to Wacholder et al. (1992, and references therein) for a discussion on this method particularly regarding ensuring of time comparability of the "exposed" and control samples, to Schulz and Grimes (2002) for a discussion on the comparison of cohort studies as applied here versus case-control studies, and to Grimes and Schulz (2005) for a discussion of selection biases in samples and their controls (specifically their example on pp. 1429-1430).

We define a series of values of geomagnetic variability in order to form sets of dates including different ranges of exposure, i.e., of geomagnetic variability, so that each high exposure date is matched by representative low exposure dates as controls. We create exposure sets by selecting a series of threshold levels corresponding to percentages of all dates with the most intense geomagnetic activity as measured by the metric G. Specifically, we determined the values of G for which geomagnetic activity, sorted from least active upward, includes 67%, 75%, 82%, 90%, 95%, and 98% of all dates in our study period. For each threshold value we selected the dates with G exceeding that threshold (with possible further selection criteria as described below). For each percentile set we compute the mean daily rate of incident claims, n_i, as well as the standard deviation on the mean, σ_i, as determined from the events in the day-by-day claims list.

In order to form tightly matched control samples for low "exposure", we then select 3 dates within a 27-d period centered on each of the selected high-activity days. The 27-d period, also known as the Bartels period, is that characteristic of a full rotation of the solar large-scale field as viewed from the orbiting Earth; G values within that period sample geomagnetic variability as induced during one full solar rotation. This window for control sample selection is tighter than that used by *Schrijver and Mitchell* [2013] who used 100-day windows centered on dates with reported grid disturbances. For the present study we selected a narrower window to put even stronger limits on the potential effects of any possible long-term trends in factors that might influence claims statistics or geomagnetic variability. We note that there is no substantive change in our main conclusions for control windows at least up to 100 days in duration.

The three dates selected from within this 27-d interval are those with the lowest value of G smoothed with a 3-day running mean. We determine the mean claim rate, n_c, for this control set and the associated standard deviation in the mean, σ_c.

Fig. 5 shows the resulting daily frequency of claims and the standard deviations in the mean, $n_i \pm \sigma_i$, for the selected percentiles, both for the full sample A (left panel) and for sample B (right panel) from which claims were omitted that were attributed to causes not likely associated directly or indirectly with geomagnetic activity. For all percentile sets we see that the claim frequencies n_i on geomagnetically active days exceed the frequencies n_c for the control dates.

The frequency distributions of insurance claims are not Poisson distributions, as can be seen in the example in Fig. 6 (left panel): compared to a Poisson distribution of the same mean, the claims distributions on geomagnetically active dates, $N_{\rm B,a,75}$ and for control days, $N_{\rm B,c,75}$, are skewed to have a peak frequency at lower numbers and a raised tail at higher numbers; a Kolmogorov-Smirnov (KS) test suggests that the probability that $N_{\rm B,c,75}$ is consistent with a Poisson distribution with the same mean is 0.01 for this example. The elevated tail of the distribution relative to a Poisson distribution suggests some correlation between claims events, which is of interest from an actuarial perspective as it suggests a nonlinear response of the power system to space weather that we cannot investigate further here owing to the signal to noise ratio of the results given our sample.

For the case shown in Fig. 6 for the 25% most geomagnetically active dates in set B, a KS test shows that the probability that $N_{\rm B,a,75}$ and $N_{\rm B,c,75}$ are drawn from the same parent distribution is of order 10^{-14}, i.e. extremely unlikely.

The numbers that we are ultimately interested in are the excess frequencies of claims on geomagnetically active

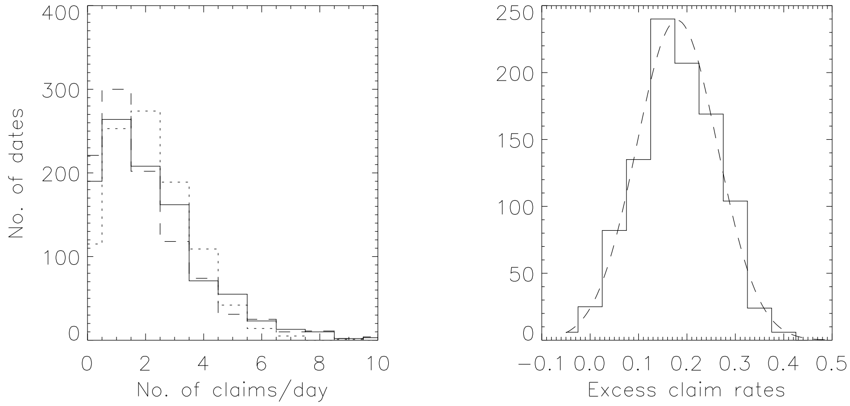

Figure 6. *(left) Distribution of the number of claims per geomagnetically active day for set* B *for the top 25% of* G *values (solid) compared to that for the distribution of control dates (divided by 3 to yield the same total number of dates; dashed). For comparison, the expected histogram for a random Poisson distribution with the same mean as that for the geomagnetically active days is also shown (dotted). (right) Distribution (solid) of excess daily claim frequencies during geomagnetically active days (defined as in the left panel) over those on control dates determined by repeated random sampling from the observations (known as the bootstrap method), compared to a Gaussian distribution (dashed) with the same mean and standard deviation.*

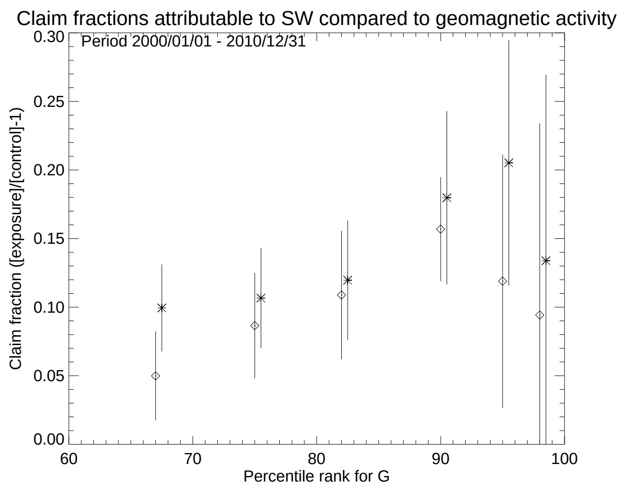

Figure 7. *Relative excess claim frequencies statistically associated with geomagnetic activity (difference between claim frequencies on geomagnetically active dates and the frequencies on control dates as shown in Fig. 5, i.e.,* $(n_i - n_c)/n_c$ *for the full sample (A; diamonds) and for the sample (B; asterisks) from which claims were removed attributable to apparently non-space-weather related causes.*

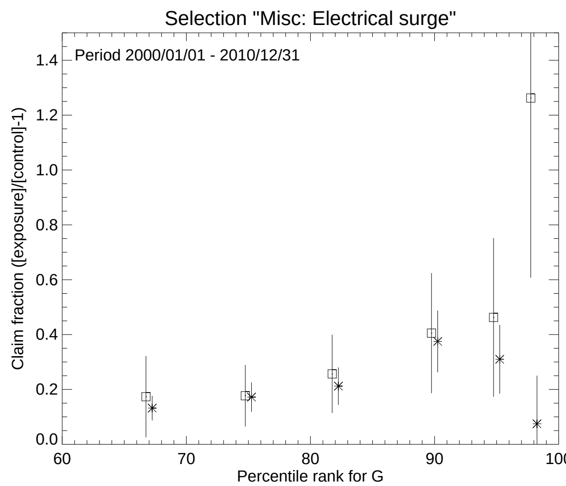

Figure 8. *Same as Fig. 7 but for sample* B *limited to those claims attributed to "Misc.: Electrical surge" (asterisks) (for 57% of the cases in that sample), compared to the fraction of high-voltage power-grid disturbances statistically associated with geomagnetic activity (squares).*

dates over those on the control dates, and their uncertainty. For the above data set, we find and excess daily claims rate of $(n_{\rm B,i} - n_{\rm B,c}) \pm \sigma_{\rm B} = 0.20 \pm 0.08$. The uncertainty $\sigma_{\rm B}$ is in this case determined by repeated random sampling of the claims sample for exposure and control dates, and subsequently determining the standard deviation in a large sample of resulting excess frequencies (using the so-called bootstrap method). The distribution of excess frequencies (shown in the righthand panel of Fig. 6) is essentially Gaussian, so that the metric of the standard deviation gives a useful value to specify the uncertainty. We note that the value of $\sigma_{\rm B}$ is comparable to the value $\sigma_{a,c} = (\sigma_{\rm a}^2 + \sigma_{\rm b}^2)^{1/2}$ derived by combining the standard deviations for the numbers of claims per day for geomagnetically active dates and the control dates, which in this case equals $\sigma_{a,c} = 0.07$. Thus, despite the skewness of the claim count distributions relative to a Poisson distribution as shown in the example in the left panel of Fig. 6, the effect of that on the uncertainty in the excess claims rate is relatively small. For this reason, we show the standard deviations on the mean frequencies in Figs. 5-10 as a useful visual indicator of the significance of the differences in mean frequencies.

Fig. 7 shows the relative excess claims frequencies, i.e., the relative differences $r_e = (n_i - n_c)/n_c$ between the claim frequencies on geomagnetically active dates and those on the control dates, thus quantifying the claim fraction statistically associated with elevated geomagnetic activity. The uncertainties shown are computed as $\sigma_e =$

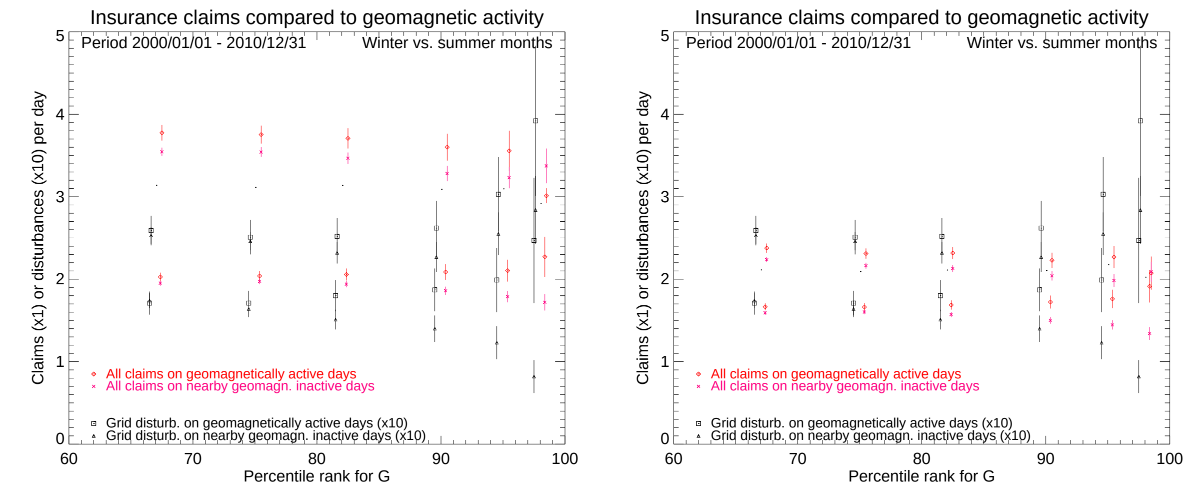

Figure 9. *As Fig. 5 but separating the winter half year (October through March) from the summer half year (April through September), for the full sample of insurance claims (set* A*, left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). Values for the summer months are shown offset slightly towards the left of the percentiles tested (98, 95, 90, 82, 75, and 67) while values for the winter months are offset to the right. Values for the winter season are systematically higher than those for summer months.*

$(\sigma_i^2/n_i^2 + \sigma_c^2/n_c^2)^{1/2}\, r_e$, i.e., using the approximation of normally distributed uncertainties, warranted by the arguments above. We note that the relative rate of claims statistically associated with space weather is slightly higher for sample B than for the full set A consistent with the hypothesis that the claims omitted from sample A to form sample B were indeed preferentially unaffected by geomagnetic activity. Most importantly, we note that the rate of claims statistically associated with geomagnetic activity increases with the magnitude of that activity.

About 59% of the claims in sample B attribute the case of the problem to "Misc.: Electrical surge", so that we can be certain that some variation in the quality or continuity of electrical power was involved. Fig. 8 shows the relative excess claims rate $(n_i - n_c)/n_c$ as function of threshold for geomagnetic activity. We compare these results with the same metric, based on identical selection procedures, for the frequency of disturbances in the high-voltage power grid (squares). We note that these two metrics, one for interference with commercial electrical/electronic equipment and one for high-voltage power, agree within the uncertainties, with the possible exception of the infrequent highest geomagnetic activity (98 percentile) although there the statistical uncertainties on the mean frequencies are so large that the difference is less than 2 standard deviations in the mean values.

To quantify the significance of the excess claims frequencies on geomagnetically active days we perform a non-parametric Kolmogorov-Smirnov (KS) test of the null hypothesis that the claims events on active and on control days could be drawn from the same parent sample. The resulting p values from the KS test, summarized in Table 1, show that it is extremely unlikely that our conclusion that geomagnetic activity has an impact on insurance claims could be based on chance, except for the highest percentiles

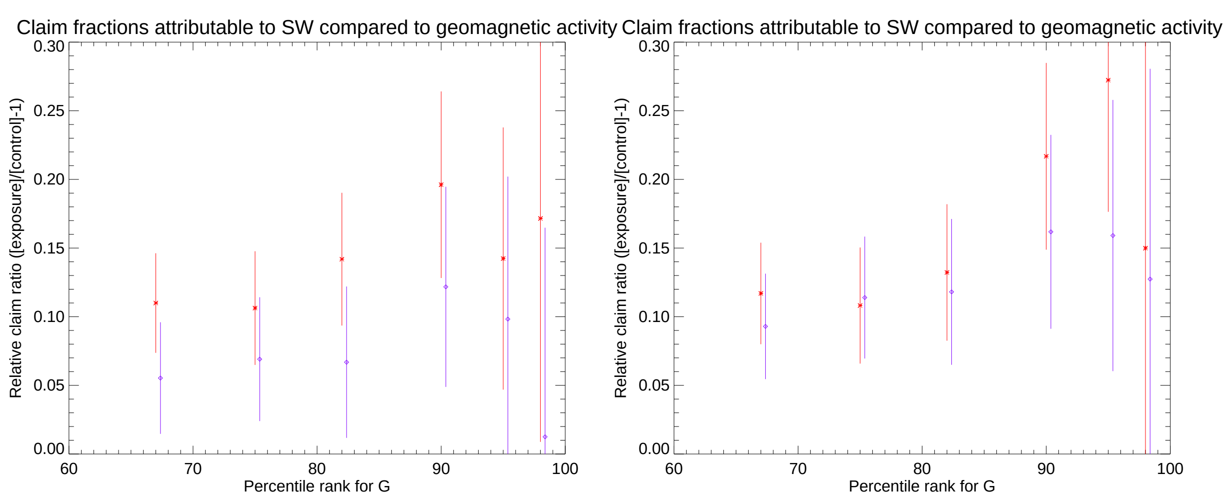

Figure 10. *Relative excess claim frequencies $(n_i - n_c)/n_i$ on geomagnetically active dates relative to those on control dates for geomagnetic latitudes below $49.^\circ 5\,N$ (asterisks, red) compared to those for higher latitudes (diamonds, purple; offset slightly to the right) for the percentiles tested (98, 95, 90, 82, 75, and 67). The lefthand panel shows the results for the full sample (A), and the righthand panel shows these for sample B from which apparently non-space-weather related events were removed (see Section 2.1).*

Table 1. Probability (p) values based on a Kolmogorov-Smirnov test that the observed sets of claims numbers on geomagnetically active dates and on control dates are drawn from the same parent distribution, for date sets with the geomagnetic activity metric G exceeding the percentile threshold in the distribution of values.

Percentile	All claims		Attr. to electr. surges	
	set A	set B	set A	set B
67	$2.\times10^{-10}$	$2.\times10^{-19}$	$1.\times10^{-27}$	0
75	$3.\times10^{-7}$	$4.\times10^{-14}$	$8.\times10^{-20}$	$4.\times10^{-35}$
82	0.0004	$2.\times10^{-7}$	$1.\times10^{-13}$	$6.\times10^{-24}$
90	0.010	0.0002	$1.\times10^{-7}$	$8.\times10^{-13}$
95	0.05	0.013	0.0001	$2.\times10^{-7}$
98	0.33	0.06	0.003	0.0001

in which the small sample sizes result in larger uncertainties. We note that the p values tend to decrease when we eliminate claims most likely unaffected by space weather (contrasting set A with B) and when we limit either set to events attributed to electrical surges: biasing the sample tested towards issues more likely associated with power-grid variability increases the significance of our findings that there is an impact of space weather.

Fig. 9 shows insurance claims differentiated by season: the frequencies of both insurance claims and power-grid disturbances are higher in the winter months than in the summer months, but the excess claim frequencies statistically associated with geomagnetic activity follow similar trends as for the full date range. The same is true when looking at the subset of events attributed to surges in the low-voltage power distribution grid.

Figure 11 shows a similar diagram to that on left-hand side of Fig. 9, now differentiating between the equinox periods and the solstice periods. Note that although the claims frequencies for the solstice periods are higher than those for the equinox periods, that difference is mainly a consequence of background (control) frequencies: the fractional excess frequencies on geomagnetically active days relative to the control dates are larger around the equinoxes than around the solstices.

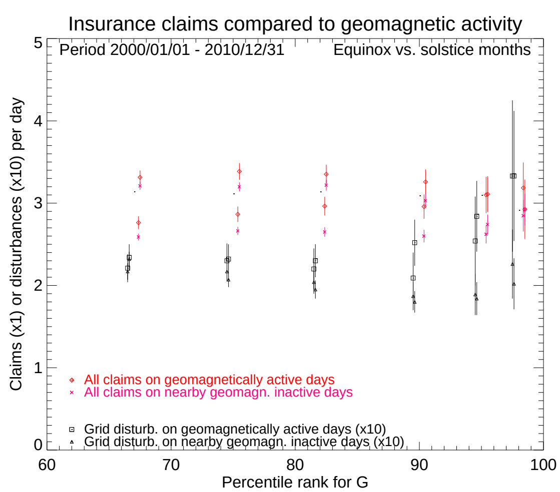

Figure 11. *As Fig. 9 but separating the months around the equinoxes (February-April and August-October) from the complementing months around the solstices, for the full sample of insurance claims (set* A*). Values for the equinox periods are shown offset slightly towards the left of the percentiles tested (98, 95, 90, 82, 75, and 67) while values for the solstice months are offset to the right. Mean claims frequencies for the solstice periods are systematically higher than those for equinox periods, but the frequencies for high-G days in excess of the control sample frequencies is slightly larger around the equinoxes than around the solstices.*

Fig. 10 shows the comparison of claim ratios of geomagnetically active dates relative to control dates for states with high versus low geomagnetic latitude, revealing no significant contrast (based on uncertainties computed as described above for Fig. 7).

4. Discussion and conclusions

We perform a statistical study of North-American insurance claims for malfunctions of electronic and electrical equipment and for business interruptions related to such malfunctions. We find that there is a significant increase in claim frequencies in association with elevated variability in the geomagnetic field, comparable in magnitude to the increase in occurrence frequencies of space weather-related disturbances in the high-voltage power grid. In summary:

- The fraction of insurance claims statistically associated with geomagnetic variability tends to increase with increasing activity from about $5-10\%$ of claims for the top third of most active days to approximately 20% for the most active few percent of days.
- The overall fraction of all insurance claims statistically associated with the effects of geomagnetic activity is $\approx 4\%$. With a market share of about 8% for Zurich NA in this area, we estimate that some 500 claims per year are involved overall in North America.
- Disturbances in the high-voltage power grid statistically associated with geomagnetic activity show a comparable frequency dependence on geomagnetic activity as do insurance claims.
- We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude.

For our study, we use a quantity that measures the rate of change of the geomagnetic field regardless of what drives that. Having established an impact of space weather on users of the electric power grid, a next step would be to see if it can be established what the relative importance of various drivers is (including variability in the ring current, electrojetc, substorm dynamics, solar insolation of the rotating Earth, ...), but that requires information on the times and locations of the impacts that is not available to us.

The claims data available to us do not allow a direct estimate of the financial impacts on industry of the malfunctioning equipment and the business interruptions attributable to such malfunctions: we do not have access to the specific policy conditions from which each individual claim originated, so have no information on deductable amounts, whether (contingency) business interruptions were claimed or covered or were excluded from the policy, whether current value or replacement costs were covered, etc. Moreover, the full impact on society goes well beyond insured assets and business interruptions, of course, as business interruptions percolate through the complex of economic networks well outside of direct effects on the party submitting a claim. A sound assessment of the economic impact of space weather through the electrical power systems is a major challenge, but we can make a rough order-of-magnitude estimate based on existing other studies as follows.

The majority (59% in sample B) of the insurance claims studied here are explicitly attributed to "Misc.: electrical surge", which are predominantly associated with quality or continuity of electrical power in the low-voltage distribution networks to which the electrical and electronic components are coupled. Many of the other stated causes (see

Section 2.1) may well be related to that, too, but we cannot be certain given the brevity of the attributions and the way in which these particular data are collected and recorded. Knowing that in most cases the damage on which the insurance claims are based is attributable to perturbations in the low-voltage distribution systems, however, suggests that we can look to a study that attempted to quantify the economic impact of such perturbations on society.

That study, performed for the Consortium for Electric Infrastructure to Support a Digital Society" (CEIDS) [*Lineweber and McNulty*, 2001], focused on the three sectors in the US economy that are particularly influenced by electric power disturbances: the digital economy (including telecommunications), the continuous process manufacturing (including metals, chemicals, and paper), and the fabrication and essential services sector (which includes transportation and water and gas utilities). These three sectors contribute approximately 40% of the US Gross Domestic Product (GDP).

Lineweber and McNulty [2001] obtained information from a sampling of 985 out of a total of about 2 million businesses in these three sectors. The surveys assessed impact by "direct costing" by combining statistics on grid disturbances and estimates of costs of outage scenarios via questionnaires completed by business officials. Information was gathered on grid disturbances of any type or duration, thus resulting in a rather complete assessment of the economic impact. The resulting numbers were corrected for any later actions to make up for lost productivity (actions with their own types of benefits or costs).

For a typical year (excluding, for example, years with scheduled rolling blackouts due to chronic shortages in electric power supply), the total annual loss to outages in the sectors studied is estimated to be \$46 billion, and to power quality phenomena almost \$7 billion. Extrapolating from there to the impact on all businesses in the US from all electric power disturbances results in impacts ranging from \$119 billion/year to \$188 billion/year (for about year-2000 economic conditions).

Combining the findings of that impact quantification of all problems associated with electrical power with our present study on insurance claims suggests that, for an average year, the economic impact of power-quality variations related to elevated geomagnetic activity may be a few percent of the total impact, or several billion dollars annually. That very rough estimate obviously needs a rigorous follow-up assessment, but its magnitude suggests that such a detailed, multi-disciplinary study is well worth doing.

Acknowledgments. We are grateful to the three reviewers of our manuscript for their guidance to improve the presentation of our results. This work was supported by Lockheed Martin Independent Research funds (CJS, SMP). The results presented in this paper rely on data collected at magnetic observatories. We thank the national institutes that support them and INTERMAGNET for promoting high standards of magnetic observatory practice (www.intermagnet.org). The insurance claims data are accessible at http://www.lmsal.com/∼schryver/claims/claims.csv.

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Generator Thermal Stress during a Geomagnetic Disturbance

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***Abstract*— this paper investigates the operating condition of the generator during a Geomagnetic Disturbance (GMD). Generators are sensitive to harmonics and negative sequence currents, caused by the half-cycle saturation of the generator step-up transformer due to Geomagnetically Induced Current. Such harmonic currents can cause rotor heating, alarming, and the loss of generation.**

Based on the time-domain simulation in the EMTP, this study investigates the order and magnitude of the harmonics which impact the generator, and determines the rotor heating level due to such harmonics, at various levels of the GIC. The study reveals that the generator can reach its thermal capability limit at moderate GIC levels. However, the existing standards, e.g., IEEE Standards C50.12 and C50.13, fail to account for such operating conditions, and the corresponding recommendations underestimate the rotor heating level. As such, the negative sequence relays may not accurately operate under GMDs. A modification to the standards is also required which is proposed in this study.

***Index Terms*-- Generator, Power Transformer, Geomagnetically Induced Current, Negative Sequence Relay.**

I. INTRODUCTION

Geomagnetic disturbance or Solar Magnetic Storm refers to the phenomena caused by the solar flare and coronal mass ejection activities. Due to explosion on the sun surface, a large amount of the charged particles, which is also known as the solar wind, is released to the space. If the solar wind strikes the earth, it distorts the dc magnetic field of the earth and a slowly varying voltage is induced in the earth and on the power transmission lines. The induced dc voltage is discharged to ground through the grounded neutral of the power transformers and generates a quasi-dc current which is referred to as Geomagnetically Induced Current (GIC). The GIC biases the transformer core in one direction, and causes a half-cycle saturation. The saturation of transformers in turn increases the reactive power demand which endangers the power system stability. Furthermore, the unidirectional saturation of transformers creates harmonics which can cause several adverse consequences in the power system [1]-[3]. The Hydro-Quebec power system blackout and the failure of a Generator Step-Up (GSU) transformer in Salem nuclear plant, New Jersey, on March 13, 1989 are examples of the consequences of a GMD event [4]-[6].

The operation condition of generators is also influenced by the GIC. During a GMD, the increase of the reactive power demand due to the saturation of the system transformers should be compensated by the generators. As such, the generator field current increases to respond to the increase of the VAR demand. This in turn may raise another concern that the VAR generation limit of the generator can be reached, and the generator is not able to further inject reactive power to the system and regulate the system voltage.

Generators are sensitive to harmonics and the fundamental frequency negative sequence current. The negative sequence current due to the voltage imbalance induces a twice frequency in the rotor, and causes rotor heating [7]. Similarly, the current harmonics induce eddy current in the rotor surface, and produce additional power loss and excessive rotor heating [7]. Another undesired impact of harmonics and negative sequence currents is the generation of the oscillatory torque and vibration of the generator. As such, the mechanical parts of the generator are subjected to mechanical stress and the risk of damage. During the past GMD events, several abnormal conditions associated with the generators have been reported [3]. However, a quantitative investigation of the magnitude of the generator negative sequence current and the current harmonics under a geomagnetic disturbance has not been carried out.

In this paper, the magnitude and the order of the harmonics generated by the saturated transformer due to GIC are determined. Based on the time-domain simulation of a generation unit including the generator, the connected 500kV GSU transformer, and the transmission line, the harmonics and the negative sequence current impressed on the generator are obtained. This study reveals that the generator can reach its

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thermal capability limit at moderate GIC levels and the available standards do not address this issue.

II. Saturation of GSU Transformer due to GIC

When the GSU transformer is subjected to GIC, the dc current generates a dc flux offset in the core and results in a shift in the core flux, Fig. 1. The ac flux due to the system voltage is superimposed on the dc flux. If the peak of the total flux enters the saturation region of the core magnetization characteristic, the transformer is driven into a half-cycle saturation, as shown in Fig. 1. The normal transformer magnetizing current ImAC, which is small under symmetric excitation condition, increases to the unidirectional magnetizing current ImGIC, under the GIC conditions.

Fig. 2 depicts the frequency spectrum of the magnetizing current of a typical three-phase 500kV-750 MVA power transformer, when the transformer is subjected to the GIC magnitude of 100A at the neutral point of the transformer. This current corresponds to 33.3 A/phase GIC, since the geomagnetic disturbance induces the same magnitude of GIC on the three phases. Due to both unsymmetrical excitation and the core nonlinearity, the magnetizing current contains both even and odd harmonics. The frequency spectrum of Fig. 2 also reveals that the magnitudes of the harmonics are comparable with the fundamental component. Furthermore, the magnitude of the dominant harmonics gradually decreases as the order of harmonics increases. Fig. 3 shows the total harmonic distortion (THD) of the magnetizing current which exceeds 200% at the lower levels of GIC and decreases at higher GIC levels. The flow of the harmonics in the power system creates power loss, can overload the capacitor banks, increases the possibility of the resonance in the power system, and may cause mal-operation of the protective relays due to the distorted voltage and current signals.

In addition to the harmonic generation, the fundamental frequency component of the magnetizing current significantly increases with the applied GIC. Therefore, when a power system is exposed to a GMD event, the reactive power demand of the system increases. This in turn degrades the system voltage regulation and can endanger the system voltage stability. Under such conditions, maintaining the capacitor banks in service is a requirement, while they can be under stress due to the imposed harmonics. This implies that the protection settings need to be properly chosen to keep the capacitor bank in service as for as the impressed stress does not damage the capacitor.

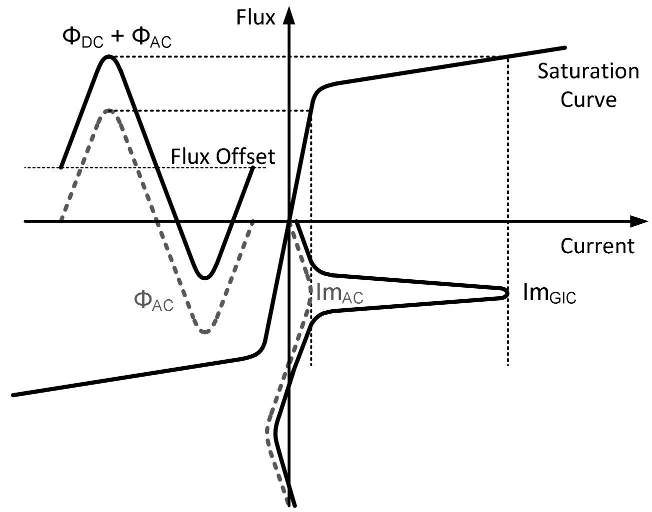

Fig. 1. Half-cycle saturation of the transformer core due to GIC

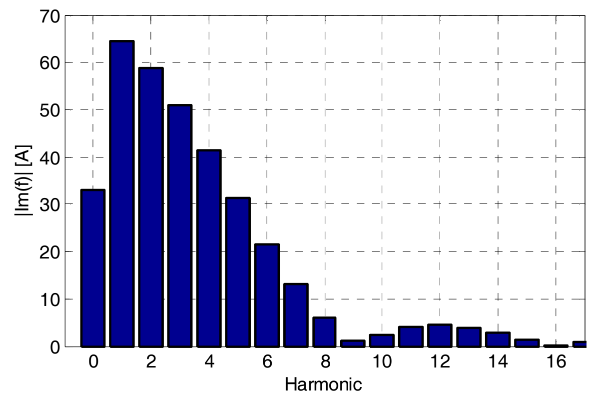

Fig. 2. Harmonics of the transformer magnetizing current at GIC=33.3 A/phase (100A at the neutral of the transformer)

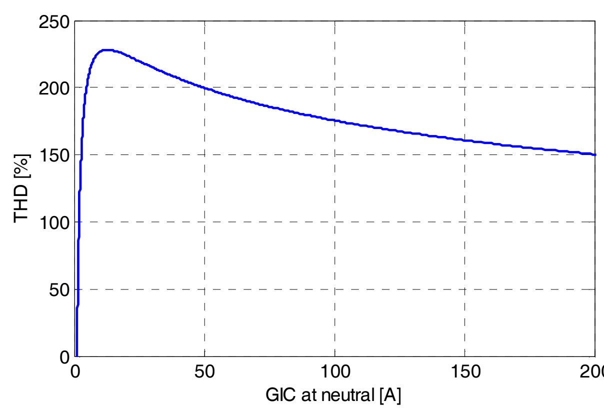

Fig. 3. Total Harmonic Distortion (THD) of the transformer magnetizing current under various GIC levels seen at the transformer neutral

III. System under Study and the Equipment Models

Fig. 4 illustrates the system under study. The generation unit includes a 26kV-892.4MVA turbo generator and the corresponding step-up transformer. The parameters of the generator are given in the Appendix. The GSU transformer is a transformer bank consisting of three single-phase units. The three-phase transformer is rated 525/26kV – 920 MVA, with a short circuit impedance of %14. The winding connection of the transformer is delta on the generator side and grounded wye on the high-voltage side. The generation unit is connected to the power grid through a 500kV transmission line with the length of 170km and the parameters given in the Appendix. The transmission line is modeled based on a frequency-dependent representation, which takes into account the actual configuration of the conductors. The line is not transposed and therefore, represents an unbalanced voltage at the GSU transformer high voltage terminals. The 500kV power grid is represented by a thevenin equivalent with the

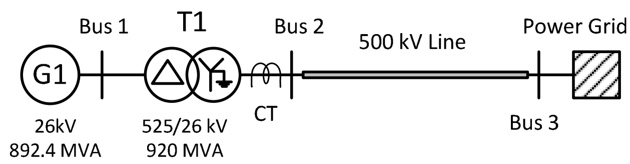

Fig. 4. System under study

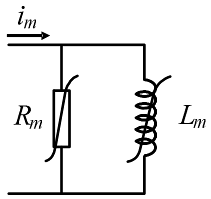

Fig. 5. Transformer core model with a dynamic core loss resistance

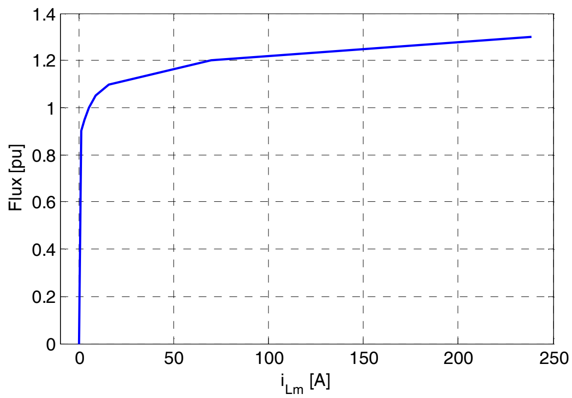

Fig. 6. Saturation curve of the GSU transformer

equivalent impedance deduced based on the short circuit level of 50kA, at Bus 3, Fig. 4.

The main component of the system for the GIC studies is the transformer. The GSU transformer consists of three single-phase units. The transformer core is represented based on a nonlinear inductance in parallel with a nonlinear dynamic core loss resistance, Fig. 5. Figs 6 and 7 illustrate the characteristics of the nonlinear inductance and the dynamic core loss resistance, respectively. These characteristics are obtained such that the transformer no-load test current and core loss are accurately duplicated. Unlike the conventional transformer models in which the core loss resistance is constant, Fig. 7 indicates that as the excitation level increases the core loss resistance, i.e., the slope of the characteristic, decreases. Based on the characteristics of Figs. 6 and 7, Fig. 8 shows the overall characteristic of the core model of Fig. 5, which is close to an actual hysteresis core characteristic. Fig. 8 illustrates the core characteristic at the excitation level of 1.1pu.

IV. Generator Rotor Heating due to GIC

During a geomagnetic disturbance, the saturation of power transformers causes the system imbalance and generates harmonics. Such abnormal voltage and currents subject the generator to thermal and mechanical stresses. The generators are usually protected by the negative-sequence relays which

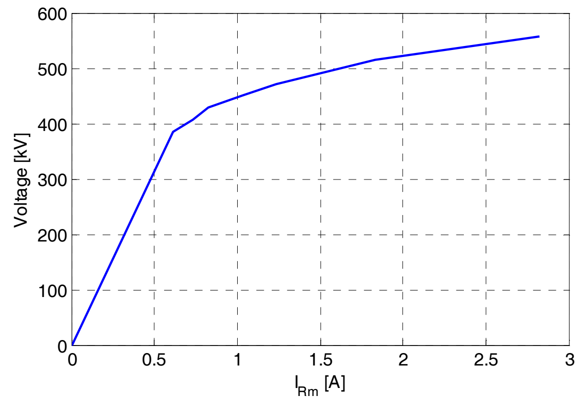

Fig. 7. Characteristic of the dynamic core loss resistance of the GSU transformer

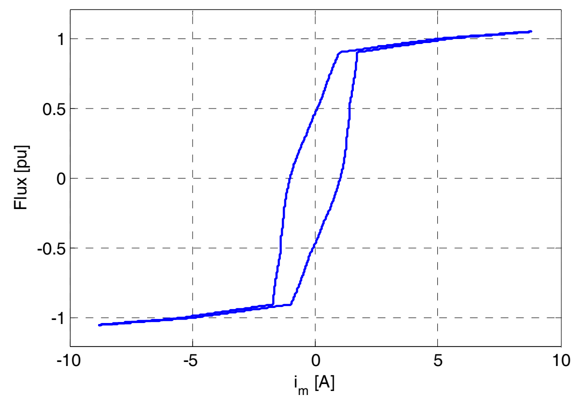

Fig. 8. Overall characteristic of the GSU transformer core at 1.1pu excitation based on the dynamic core loss model of Fig. 5 and the characteristics of Figs. 6 and 7.

operate based on an inverse-time characteristic to maintain a permissible $I^2t=constant$ thermal capability curve.

IEEE Standards C50.12 and C50.13 [9]-[10] provide recommendations for the negative-sequence capability of the salient-pole and cylindrical synchronous generators, respectively. For a turbo cylindrical generator, the permissible continuous negative sequence is deduced as

$$I_2 = 8\text{-}(MVA\text{-}350)/300, \qquad (1)$$

where I_2 is the permissible value in per-unit of the rated generator current, and MVA is the rated power of the generator in megavolt-ampere. Accordingly, the permissible continuous negative sequence for the generator under study is 6.2%.

The standards C50.12 and C50.13 also provide the guideline to take into account the impacts of the stator harmonic currents on the rotor heating. The recommendations are based on finding an equivalent negative sequence current which generates the same heat as that produced by the actual negative sequence and all the harmonics. The standards require that the equivalent negative sequence current shall not exceed the value calculated in (1). Furthermore, if 25% of the permissible current (1) is exceeded, the manufacturer shall be notified about the expected harmonics during the design or to determine whether or not the generator can withstand the harmonic heating. The equivalent negative sequence current is calculated as [9], [10],

$$I_{2eq} = \sqrt{I_2^{\,2} + \sum_n \sqrt{\frac{n+i}{2}} I_n^{\,2}}\,, \qquad (2)$$

where,

$i = +1$ when $n = 5, 11, 17, etc.,$

$i = -1$ when $n = 7, 13, 19, etc.$

Equation (2) is based on the fact that under continuous operating conditions, the system harmonic currents only include the odd harmonics of the fundamental frequency. In addition, the triplen harmonics appear as zero sequence currents and are eliminated by the delta winding of the GSU transformers. As such, the harmonic orders n=6k-1, k=1, 2, …, are negative sequence, and the associate air gap fluxes rotate in the opposite direction of the generator rotation. Therefore, the frequency of the induced eddy current on the rotor surface is the sum of the fundamental frequency and the harmonic frequency. On the other hand, harmonics n=6k+1, k=1, 2, …, are positive sequence harmonics and induces one order lower frequency on the rotor.

However, during a geomagnetic disturbance, both even and odd harmonics present in the generator current. Consequently, for the GIC analysis, equation (2) requires to be modified and extended to both even and odd harmonics, considering that

Negative sequence harmonics: $n = 3k-1, \quad k=1, 2,\ldots,$

Positive sequence harmonics: $n = 3k+1, \quad k=1, 2, \ldots \qquad (3)$

Since the GMD is a slowly varying event which can prolong for a few hours, the unbalanced condition and the generated harmonics caused by GIC can be considered in the context of the continuous capability of the generator. The IEEE Standard C37.102 on the protection of the AC generators [11] recommends that a relay is provided with a sensitive alarm and the negative sequence pickup range 0.03–0.20 pu to notify the operator when such a setting is exceeded.

As a case study, it is assumed that the system of Fig. 4 initially operates under normal conditions and generator G_1 delivers 800MW to the grid. Under such a condition, various levels of GIC are applied to the GSU transformer, and the generator negative sequence current and the current harmonics are calculated. The CPU time with a 2.53GHz dual-CPU computer is 4.3sec for obtaining the steady-state condition of each GIC level. Under the neutral GIC of 200A, Fig. 9 shows the simulated waveforms of the transformer magnetizing currents, and Fig. 10 depicts the harmonic components of the generator current. Due to the balanced GIC flowing in all phases, the dc current magnitude of the phase current is one third of the GIC observed at the neutral point of the GSU transformer. Fig. 10 indicates that the second harmonic is the dominant one, and the 4th and the 7th harmonics are also present in the generator current.

Table I summarizes the calculated fundamental component (I_2) and the effective negative sequence current (I_{2eq}) of the generator for various levels of the neutral GIC, in the range of 100A to 300A. Such a GIC range is considered as the moderate level of GMD. Based on the permissible negative sequence current of 6.19%, Table I reveals that at the moderate neutral GIC of 150A and higher, the effective negative sequence current exceeds the capability limit of the generator and can cause damage to the generator rotor. Even if the negative sequence relay of the generator filters the harmonics, the fundamental frequency of the negative sequence current (I2) is within the alarming range (higher than 3%) at the significantly lower GIC levels.

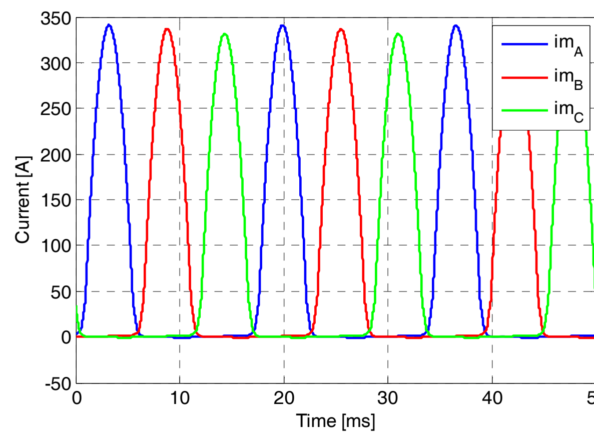

Fig. 9. Generator current harmonics under GIC of 200A at the neutral of the GSU transformer

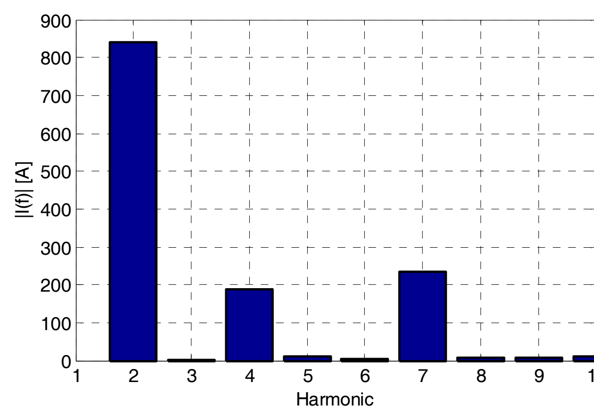

Fig. 10. Generator current harmonics under the transformer neutral GIC of 200A

TABLE I
FUNDAMENTAL FREQUENCY AND EFFECTIVE NEGATIVE SEQUENCE CURRENTS WHICH CAUSE ROTOR HEATING AT VARIOUS GIC LEVELS (PERMISSIBLE I_{2EQ}=6.19%)

GIC at neutral (A)	HV bus voltage THD (%)	I_2 (%)	I_{2eq} (%)
100	1.38	4.28	5.37
150	2.24	4.39	6.20
200	2.71	4.41	6.78
250	2.51	4.58	7.48
300	2.13	4.71	8.07

V. CONCLUSIONS

In this study, the magnitudes of the negative sequence current and the harmonic currents which impressed on the generator during a Geomagnetic Disturbance (GMD) are investigated. The harmonics are generated by the half-cycle saturation of the GSU transformer due to the GIC. Such harmonic currents cause rotor heating, can result in the mal-operation of protective relays, and the loss of generation.

Based on the time-domain simulation, this study indicates that the relevant IEEE standards C50.12 and C50.13 require modifications to take into account the even harmonics of the generator current during a GMD event. The standards underestimate the effective negative sequence current which contributes to the rotor heating. Such an effective current determines the capability limit of the generator to withstand the fundamental negative sequence and harmonic currents and is a basis for the associated relay settings. The simulation results reveal that the generator capability limit can be exceeded at moderate GIC levels, e.g. 50A/phase, and the rotor damage is likely during a severe GMD event.

VI. APPENDIX

The generator data are based on the benchmark [8] as follows,

Parameter	Value
X_d	*1.79 pu*
X'_d	*0.169 pu*
X''_d	*0.135 pu*
X_q	*1.71 pu*
X'_q	*0.228 pu*
X''_q	*0.2 pu*
T'_{do}	*4.3 s*
T''_{do}	*0.032 s*
T'_{qo}	*0.85 s*
T''_{qo}	*0.05 s*
X_l	*0.13 pu*
R_l	*0.0 pu*

The transmission line data in per unit of 100 MVA and 500 kV are as follows. Subscripts 1 and 0 stand for positive and zero sequence impedances, respectively.

Parameter	Value
R_1	*0.00189647 pu*
X_1	*0.0214564 pu*
B_1	*2.23483961 pu*
R_0	*0.022752 pu*
X_0	*0.074057 pu*
B_0	*0.952363 pu*

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[11] *IEEE Guide for AC Generator Protection*, IEEE Standard C37.102-1995, Dec. 1995.

China Data Compared to Draft NERC Std

Geomagnetic Lattitude	12.7	deg	(furthest north point geomagnetic Lattituc
Alpha Latitude Scaling Factor	0.00431		extrapolatede with f
Beta Soil Factor	0.9		No value supplied so
E from NERC Formula (V/km)	0.03	V/km	NERC Std for a One
Observed E (V/km) in China	0.67	V/km	29 - 30 May 2005 Str or 0.2 nT/s) Not a Or
Ratio = Obs (2005) / NERC Field	22		This ratio is comparir a severe One Hundre

in China grid is 12.7 degrees
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Hundred Year Storm (i.e. 4,800 nT/min)

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SUPPLEMENTAL COMMENT OF REP. ANDREA BOLAND

I'd like to add the following, on behalf of the people of Maine and the 182 of the 185 members of the Maine State Legislature who voted to have the Maine PUC provide a report on the best information available to advise the Maine Legislature on the vulnerabilities of the Maine electric grid and the options available for protecting it. Hearings and work sessions before the Joint Committee on Energy, Utilities and Technology, on this legislation showed the electric utilities and ISO-New England to first be in denial of any real problem from GMD, and then be startlingly unable to answer many technical and operational questions posed to them b committee members. They repeatedly referred to NERC as the authority they follow, so their weak presentation diminished the confidence we might otherwise have had in NERC's own expertise and guidance. The engineer representative from ISO-New England was particularly disappointing.

Unfortunately, the Maine PUC's work has continued to look towards the utilities and NERC standards for authoritative information, even in the face of the far more detailed examinations by nationally known experts that was presented to them, and despite Central Maine Power's own historical, real-world data that was made available to them in the committee meetings. In the last scheduled meeting of the study task force, we had two presentations. One, building off Power World modeling and real-world data, found it would be important to protect eighteen of our most important transformers with neutral ground blockers and GIC monitors to achieve a survivable level of protection. The Central Maine Power presentation found it was not necessary to do anything at all, using NERC benchmarks and suppositions; they did not use their own real-world data or give answers as to why they had not.

As a state legislator, in touch with many national experts on science and policy, I have worked at understanding the problem of poor or absent standards and their consequences for the protection of the electric grid. I have studied the potential protections available, and the very low costs for critical, tested equipment that could save the State of Maine from societal and economic collapse. The costs would be pennies per household per year for just about five years. Average legislators and lay people easily see the sense of installing such protective equipment, finding that, "If it's good enough for Idaho National Labs, it should be good enough for us." It's clearly very cheap insurance. The question we all have is, "Why is this job not getting done?" The answer seems to lie ultimately with NERC and a seemingly compromised FERC, as they seem to exert so much influence over the lives of Americans.

The states are within their rights to protect their own electric grids, and several are working to do it. They should not be subjected to lies and pretensions that can threaten to compromise their own processes. I'd like to ask, as a representative of the Maine public, that NERC either find the integrity to produce, in a timely way, the excellent work product that is expected of them, and live up to the duty entrusted to them, or get out of the way of those who are more conscientiously and expertly advising the electric utilities of the United States of America.

Respectfully submitted,

Andrea Boland

Representative Andrea Boland
Sanford, Maine

Comments of John Kappenman, Storm Analysis Consultants & Curtis Birnbach, Advanced Fusion Systems Regarding NERC Draft Standard on GIC Observations and NERC Geo-Electric Field Modelling Inaccuracies

Several comments have been provided to the NERC SDT by this commenter which the NERC SDT has failed to properly assess , interpret the data and analysis provided in these comments[1,2].

The NERC SDT claimed to have examined the Chester geo-electric field using Ottawa 5 second cadence data and concluded that the geo-electric field would be substantially larger than 1 V/km calculated using the NERC modeling methods from NRCan Ottawa 1 minute data. In the White Paper, the GIC observed at Chester and a detailed knowledge of the grid verifies that the actual geo-electric field was ~2 V/km during the May 4, 1998 storm. For reasons not explained by the NERC SDT, they failed to use the 10 second cadence magnetometer data actually measured at Chester but instead only used the high cadence data from Ottawa which was over 550kM west of Chester. This Chester data was provided in Figure 15 of the Kappenman/Radasky white paper which was submitted in July 2014 and the data and comments related to that data are provided in Figure 1 of this document.

At the time that the White Paper was submitted, NERC had not yet made publicly available their geo-electric field simulation model. Therefore it was not possible to independently test the NERC model results for the 10 second data at Chester and 1 minute data from Ottawa had to be used instead, which was publicly available. Because the NERC Model is now available, this model can now be used to calculate the geo-electric field at Chester using the Chester 10 second magnetometer data and provide an even more detailed examination of the degree of error that this model is producing versus actual observations. Figure 2 provides a comparison of the 10 sec cadence magnetometer data in the NERC model versus the previously discussed 1 minute data. As this comparison shows, the NERC model using the 10 sec data still provides only a geo-electric field peak of ~1 V/km, rather than the 2 V/km necessary to agree with actual GIC observations. As discussed in the White Paper, the NERC Model is understating the actual peak by nearly a factor of 2 at this location, a large uncertainty.

1. John Kappenman, William Radasky, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard" White Paper comments submitted on NERC Draft Standard TPL-007-1, July 2014.
2. Kappenman, Birnbach , Comments Submitted to NERC on October 10, 2014

Figure 1 – Figure from Kappenman/Radasky White Paper showing locally measured 10 sec magnetometer data from Chester versus the Ottawa 1 minute data around the critical 4:39UT time span

At Chester some limited 10 second cadence magnetometer data was also observed during this storm, and Figure 15 provides a plot of the delta Bx at Ottawa (1 minute data) compared with the Chester delta Bx (10 sec) during the electrojet intensification at time 4:39UT. As this comparison illustrates that at this critical time in the storm, the disturbances at both Ottawa and Chester were nearly identical in intensity.

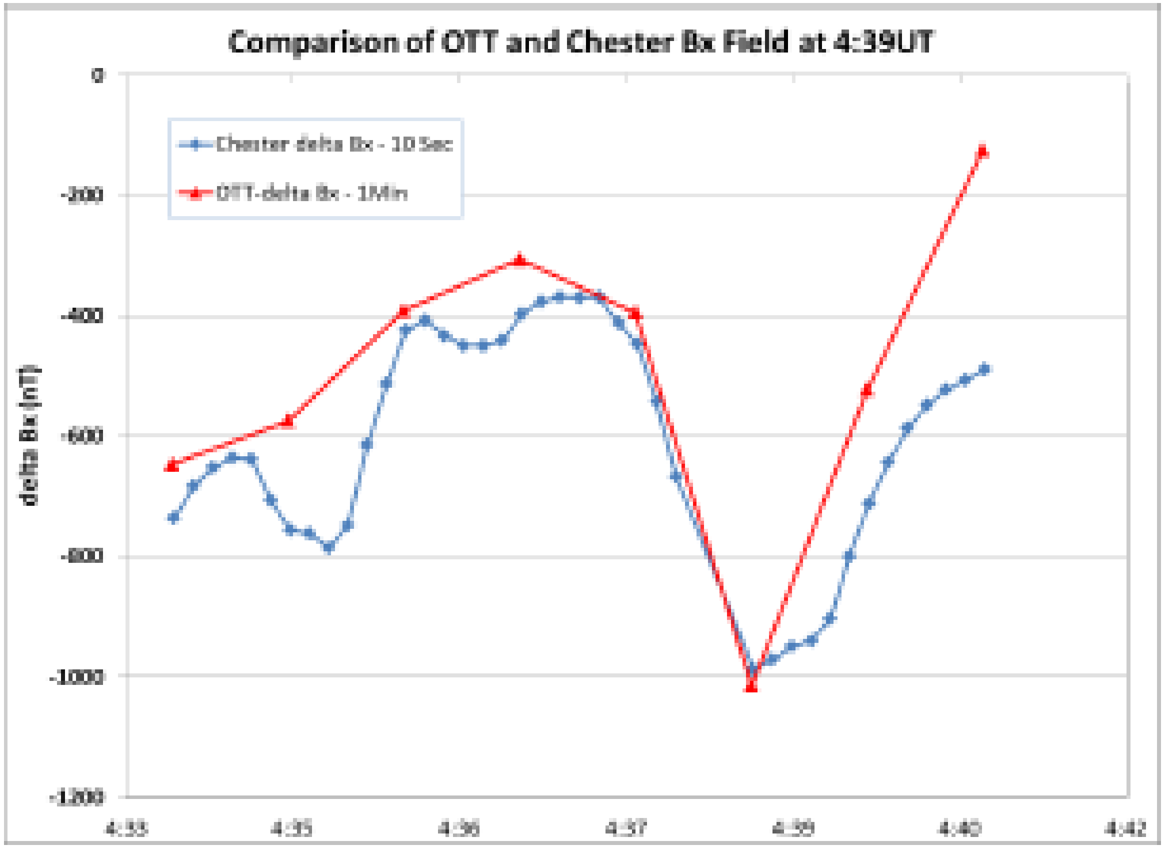
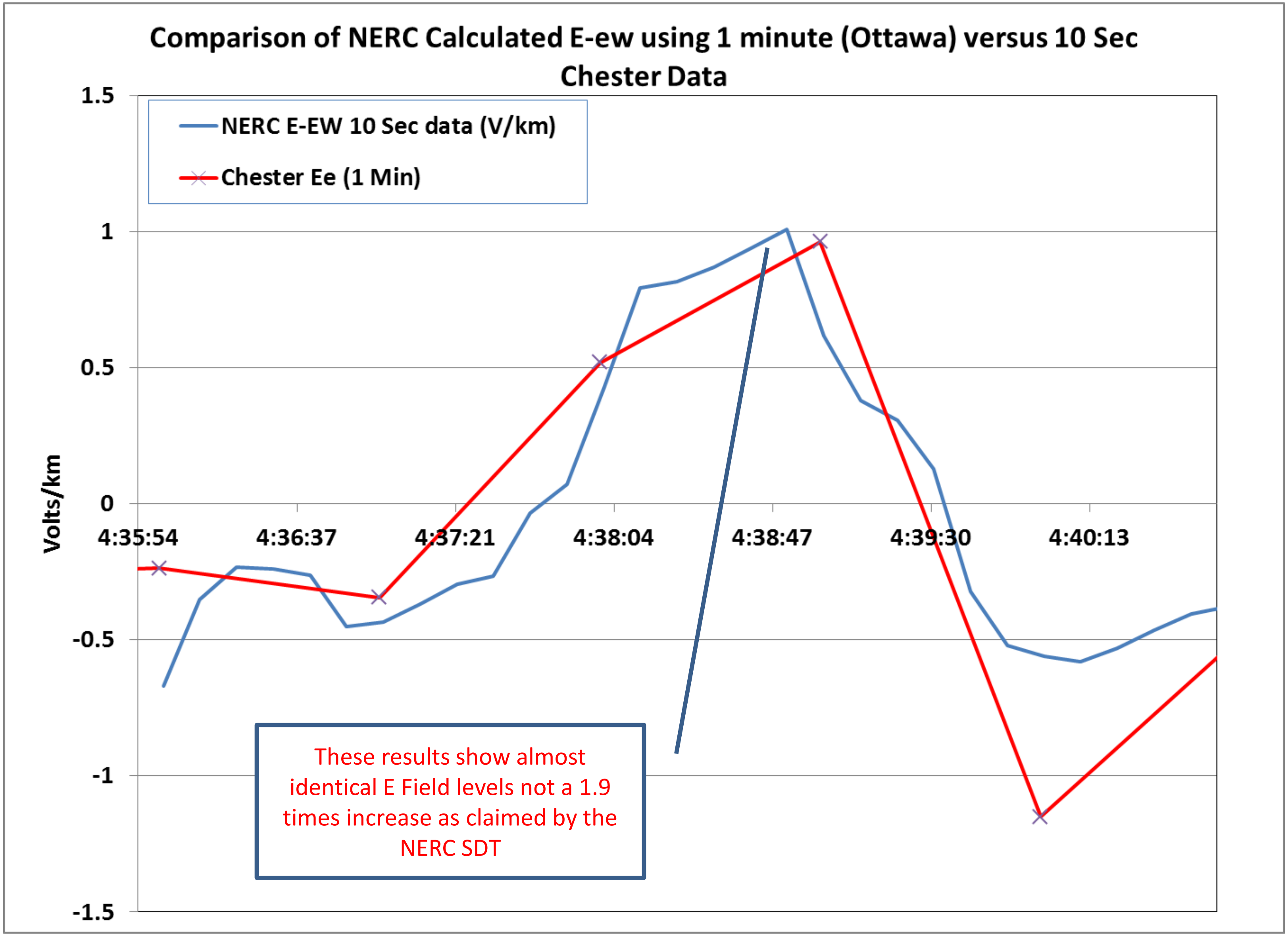


Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.

Figure 2 – Results of the NERC geo-electric field simulation model developed by Marti, et. al., with input of the 10 sec data over this study period.



The NERC SDT in their brief and inadequate response to the Kappenman/Radasky White Paper responded with the following sentence, as shown below:

> *"The method has been shown in numerous studies to accurately map the observed ground magnetic field to the geoelectric field and observed GIC (e.g., Trichtchenko et al., 2004; Viljanen et al., 2004; Viljanen et al., 2006; Pulkkinen et al., 2007; Wik et al., 2008)."*

These papers are all papers that Pulkkinen from the NERC SDT has co-authored and they also consistently confirm the same symptomatic geo-electric field simulation errors noted in the Kappenman/Radasky White Paper. In that for high dB/dt impulses, the calculated geo-electric field and resulting GIC simulations are severely understated. For example when looking at results published in the Viljanen, Pulkkinen 2004 publication noted above, the same greater than factor of 2 error shows up again in this paper as well. Figure 3 provides a model validation simulation which is Figure 8 from this paper[3]. In this figure, the intense GIC spike is highlighted in red and how the model results significantly diverge from measured GIC for these important intensifications. Figure 4 provides a plot of the observed geomagnetic field dB/dt for this same storm for an observatory close to the GIC observations and model validation provided in Figure 3. As this analysis clearly shows, at the peak dB/dt of ~500 nT/min, the Pulkkinen model diverges from reality by approximately a factor of 2 too low. This exhibits an identically similar pattern of error and low estimates as noted in Figures 31 and 32 of the Kappenman/Radasky White Paper when examining other published work of Pulkkinen. Hence the publications the NERC SDT has cited as being important to prove their model integrity, actually continue to show serious and pronounced systematic errors that have been made in their modeling approaches.

3. Fast computation of the geoelectric field using the method of elementary current systems and planar Earth models, A. Viljanen, A. Pulkkinen, O. Amm, R. Pirjola, T. Korja,*, and BEAR Working Group

Figure 3 – GIC Model validation from Viljanen, Pulkkinen paper with GIC modeling errors noted.

110 A. Viljanen et al.: Fast computation of the geoelectric field

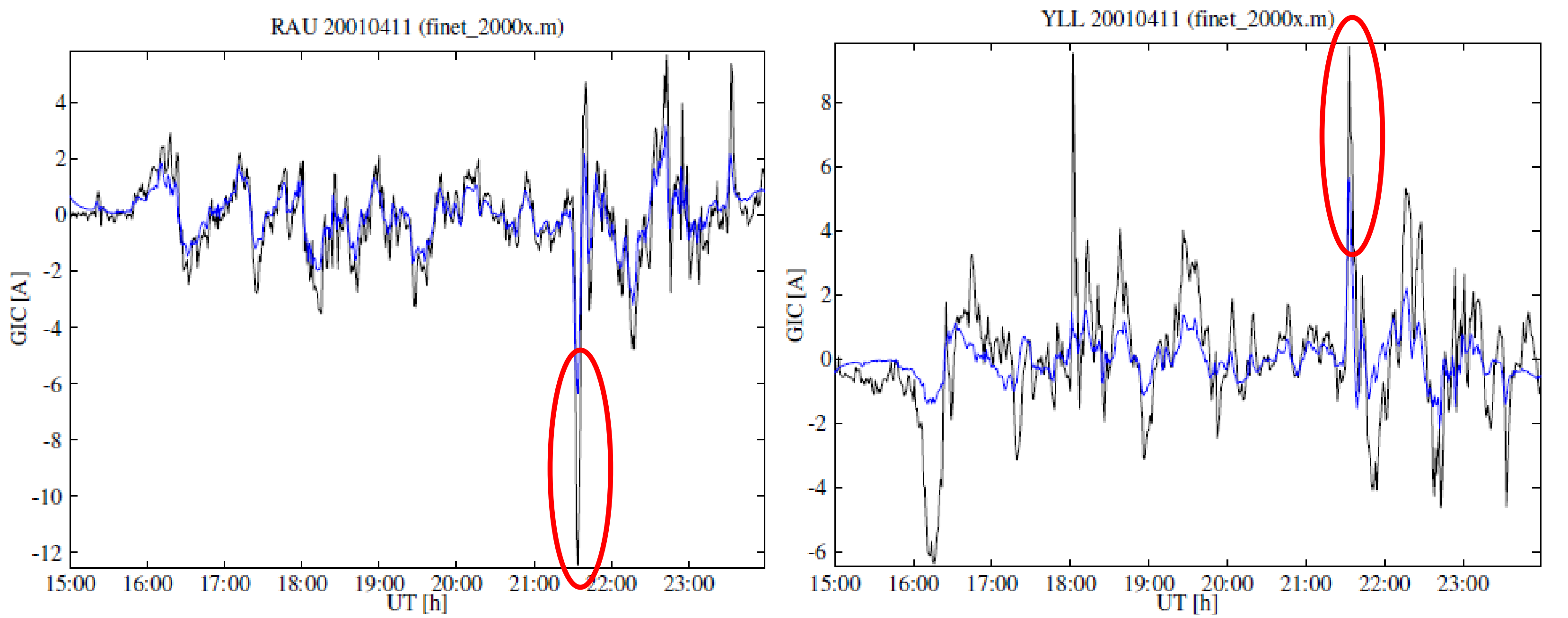
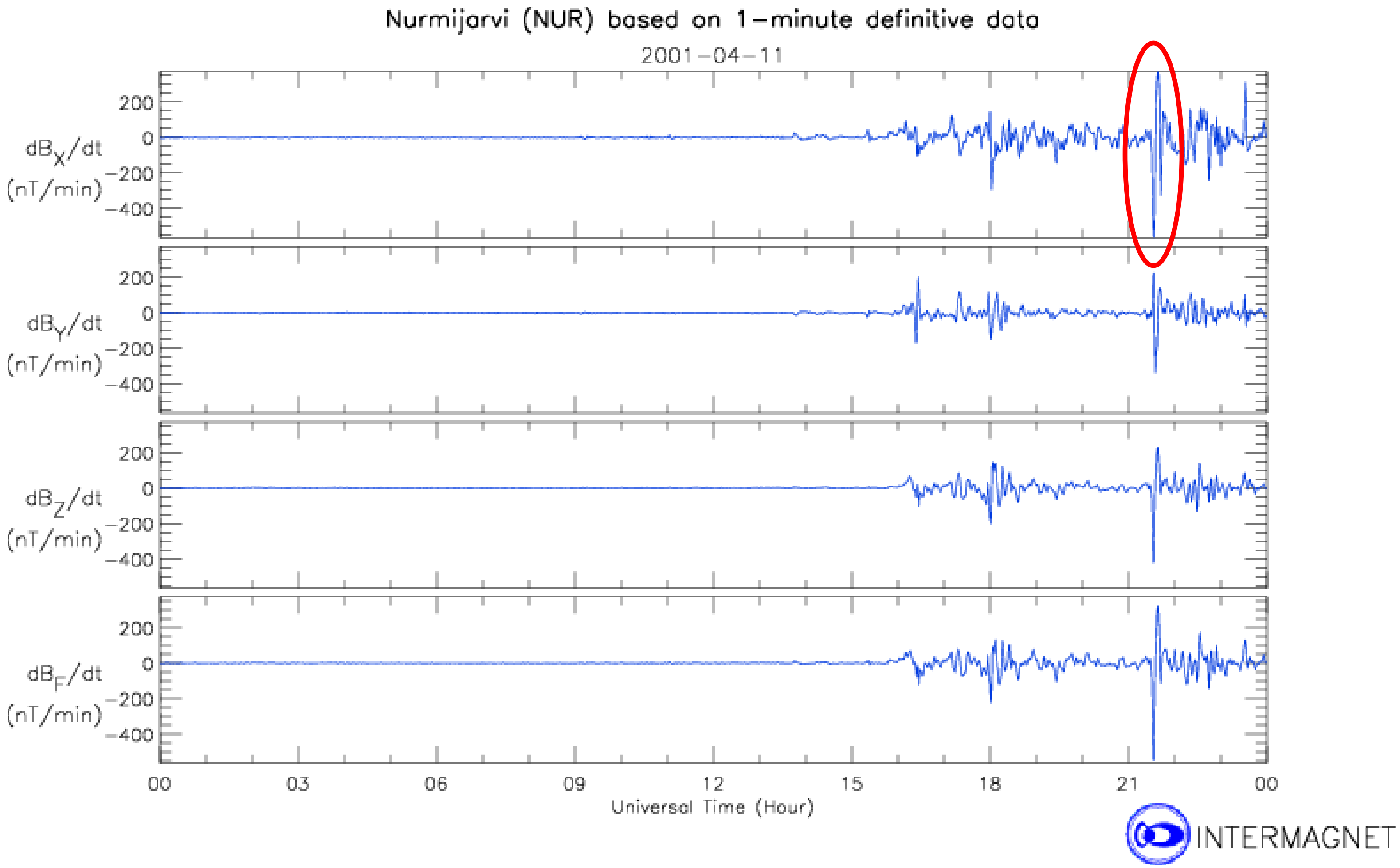


Fig. 8. Measured (black line) and modelled (blue line) geomagnetically induced currents at the Rauma (RAU) and Yllikkälä (YLL) 400 kV transformer stations on 11 April 2001.

Figure 4 – Corresponding observed dB/dt that are associated with the Viljanen, Pulkkinen paper with GIC modeling errors noted in Figure 3.



In regards to the comments provided in Oct 2014 by Kappenman/Birnbach, the NERC SDT provided this response:

> *"The commenter's approach for using GIC data to calculate geoelectric fields is valid when an accurate power system model, ground conductivity model, specific power system configuration at the time of measurement, and high data rate magnetometer data is available. Calculations are not accurate without all elements. With limited data it is not feasible to develop a technically-justified benchmark using the commenter's approach."*

It should be noted that in the case of the Chester GIC data from May 4, 1998, the details on the transmission network are well known, there is also high cadence magnetometer data as well at the location of the GIC measurement. What had not been well confirmed is the accuracy of the ground model NERC proposed or the reliability of the geo-electric field simulation model that NERC has been using. This use of GIC data and Ohm's law to validate the ground model is a well-proven approach and it is simply not credible that the NERC SDT would raise any objection to this. Further it is fully possible just using GIC observations and knowledge of the power grid (which is precisely known) to calculate the actual driving geo-electric field even if there is some uncertainty as to the local geomagnetic field.

The NERC SDT notes that "*with limited data it is not feasible to develop a technically-justified benchmark*", but in contrast that is exactly what the NERC SDT has been doing in developing their Beta factors on un-validated ground conductivity models. In a NERC GMD Task Force meeting in Atlanta on Nov 14, 2013, Dr. Jennifer Gannon from the USGS provided a presentation on the US ground models she developed for NERC and in her presentation she pointed out the large scale uncertainty in these models. In Figure 5 is a slide from her presentation where she showed an example of the ground conductivity model uncertainty for the 1D models. In Figure 6, she provides a slide which showed a factor of 4 error range in the geo-electric field when looking at two different ground model formulations that are within the range of uncertainty. She further noted that this could only be addressed by the NERC members providing GIC observations as a way to test and validate these ground models to a lower range of uncertainty. This important validation task was never performed by NERC. Yet the NERC SDT drafted a standard which as shown in Figure 7 has determined ground conductivity model Beta factors that are defined to two significant digits after the decimal point. These Beta factors are an illusion of accuracy that the NERC SDT has put forward that is not realistic and cannot be scientifically substantiated. The only means to overcome these limitations are to begin examining the GIC observations that are available, an effort which the NERC SDT has continues to refuse to perform.

Figure 5 – Slide Presented by Jennifer Gannon USGS on Ground Conductivity Model Uncertainty on Nov 14, 2013

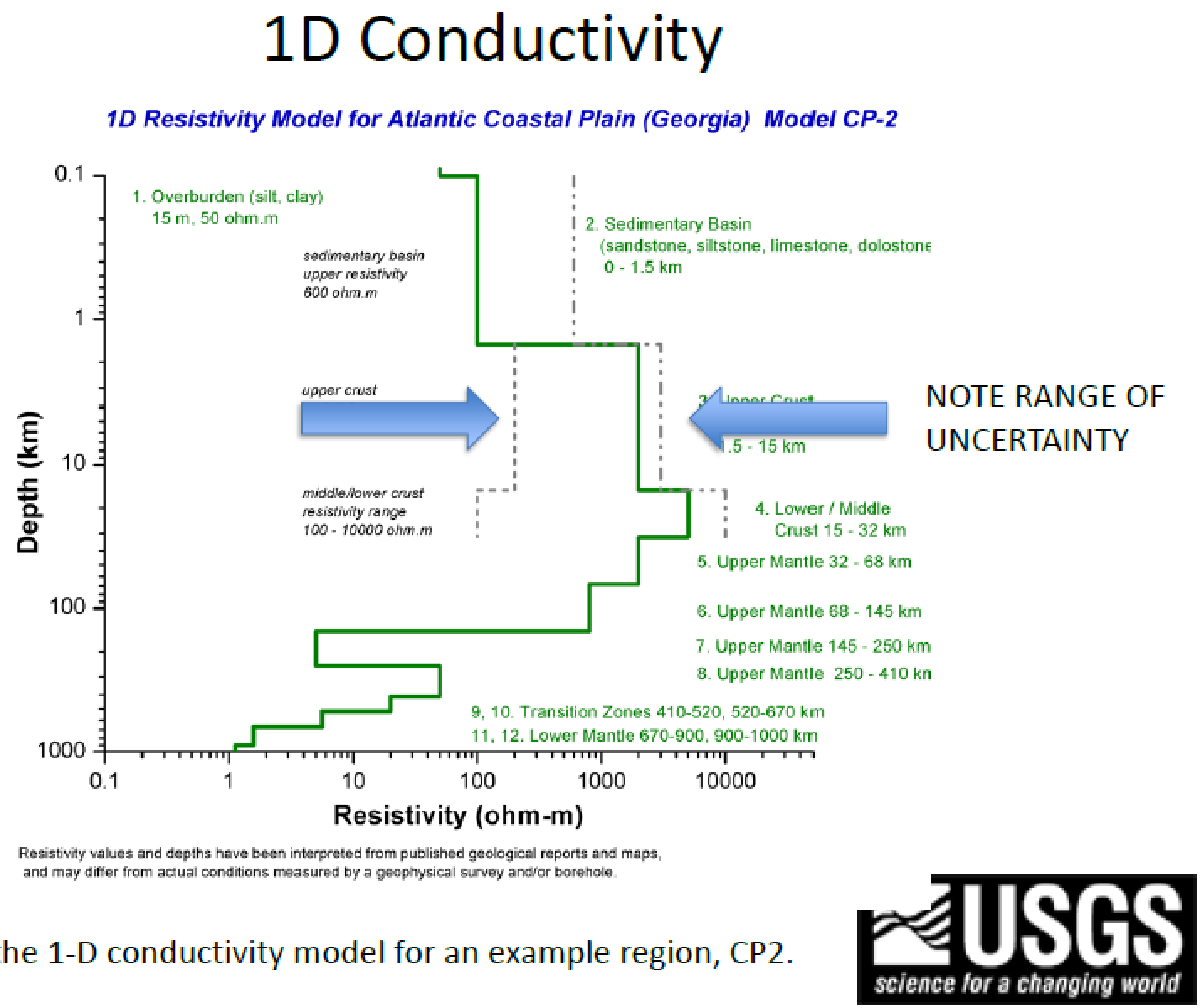


Figure 6 – Slide Presented by Jennifer Gannon USGS on Geo-Electric Field Error Range due to Ground Model Uncertainty

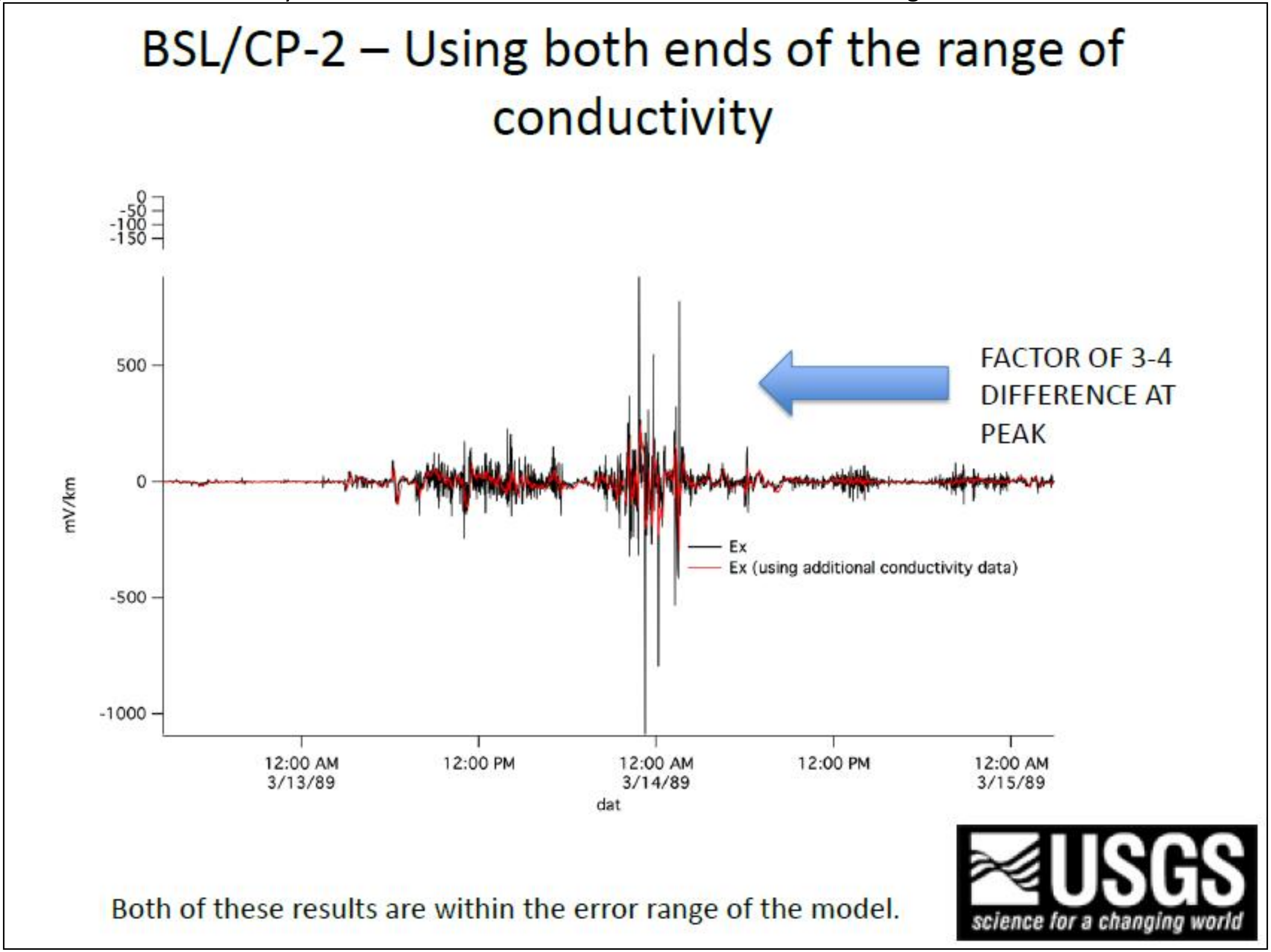


Figure 7 – NERC Draft Standard Benchmark Geo-electric field scaling factors

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CP3	0.94
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Comments of John Kappenman, Storm Analysis Consultants
Regarding NERC Draft Standard on Transformer Thermal Impact Assessments

There are serious errors and omissions in the proposed revisions from the NERC GMD Standards Task Force in regard to increasing the GIC Threshold from 15 Amps/phase to 75 Amps/phase. Both Analytical analysis and actual observation data show that problem onsets could occur at much lower GIC levels.

Figure 1 is from the Recent NERC Screening Criteria publication which shows their results of screening several transformers for thermal increases due to GIC. It must be noted that these results all ignore important factors. The most important being that the Tertiary windings on the autotransformers are the most vulnerable portions of these transformers and that the testing that was performed was conducted in a manner to obscure or hide this vulnerability. He4nce it was not properly considered. In the case of the FinnGrid transformer, the Owners and Manufacturers noted that the transformer was considered to account for relatively high stray fluxes in the design stage[1,2]. Hence this transformer may have higher GIC tolerance than exists for almost all other US transformers that were not designed with GIC considerations and have been in service for many years. Further the FinnGrid transformer is a 5 Legged Core Design which is seldom used anywhere in the US electric grid. And also has higher GIC withstand than comparable single phase transformers which largely populate the 500 and 765kV grid.

Figure 2 provides a plot of NERC Table 1 from the same publication which of the Upper Bound of Peak Metallic Hot Spot Temps that are also shown in Figure 1. Figure 3 provides a revised plot which now includes the tertiary winding heating that was provided the NERC SDT in May 2014 comments[3]. These omitted winding heating curves when added provide much lower levels of GIC withstand than the proposed NERC revision of this standard.

1. M. Lahtinen, J. Elovaara: GIC occurrences and GIC test for 400 kV system transformer. IEEE Trans on Power Delivery, vol 17, no 2, April 2002, p555-561.
2. Nordman, Hasse, “GIC Test on a 400kV System Transformer”, IEEE Transformer Standards Committee Meeting, GIC Tutorial, March,2010.
3. Kappenman, J.G., Section 2. – Analysis of Autotransformer Tertiary Winding Vulnerability, Comments filed with NERC, May 2014.

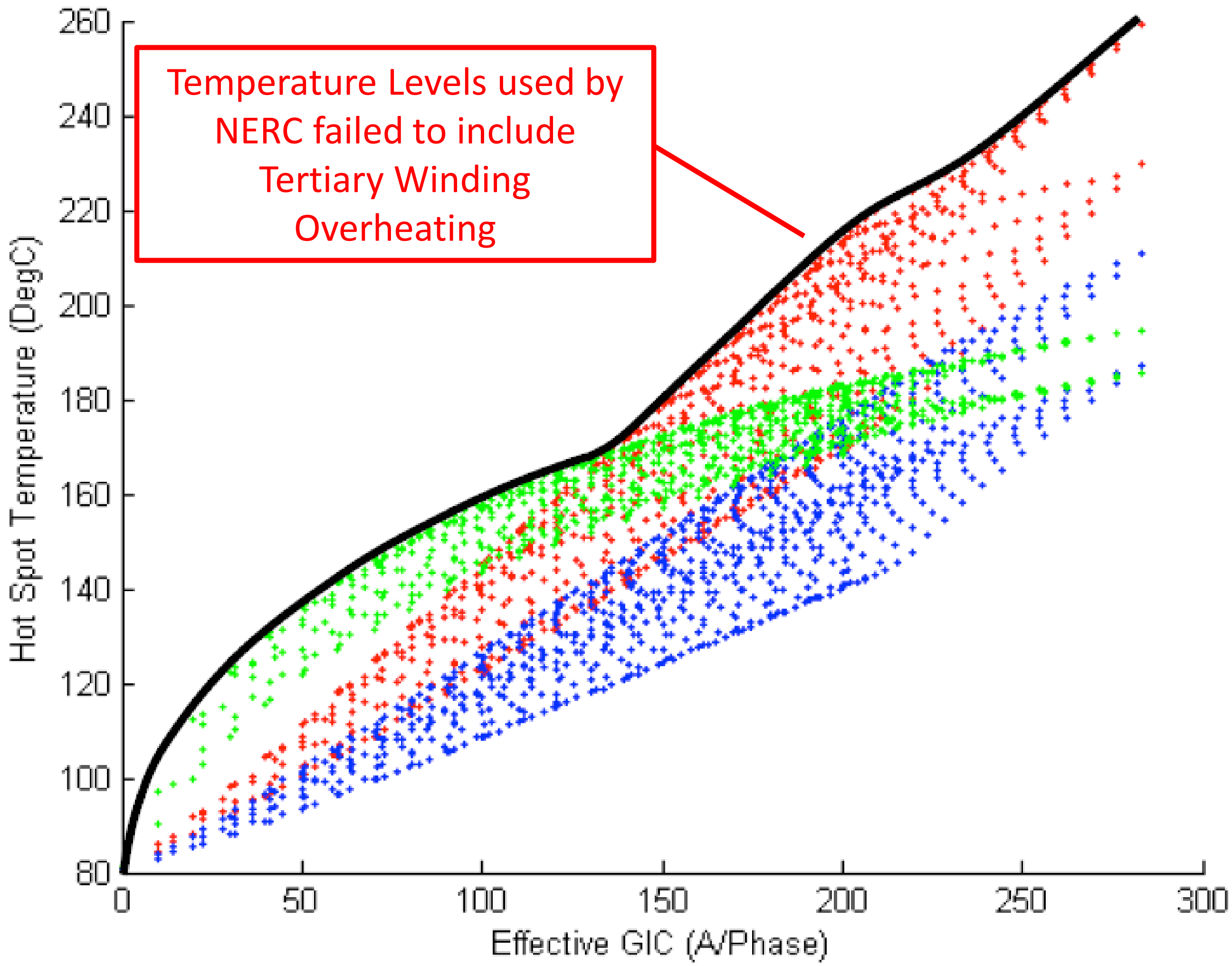


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Figure 2 – Plot of NERC Table 1 Upper Bound of Peak Metallic Hot Spot Temps

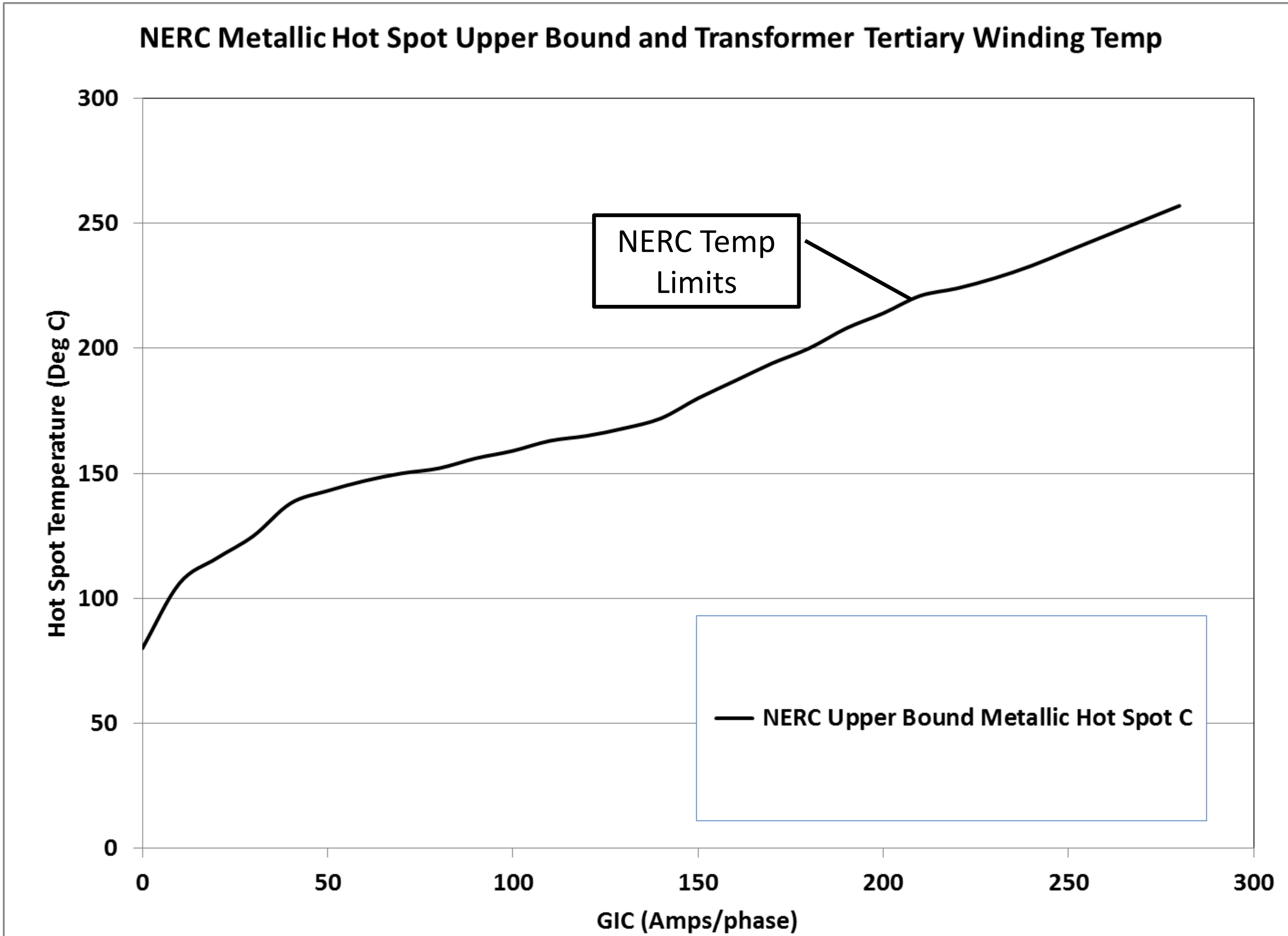
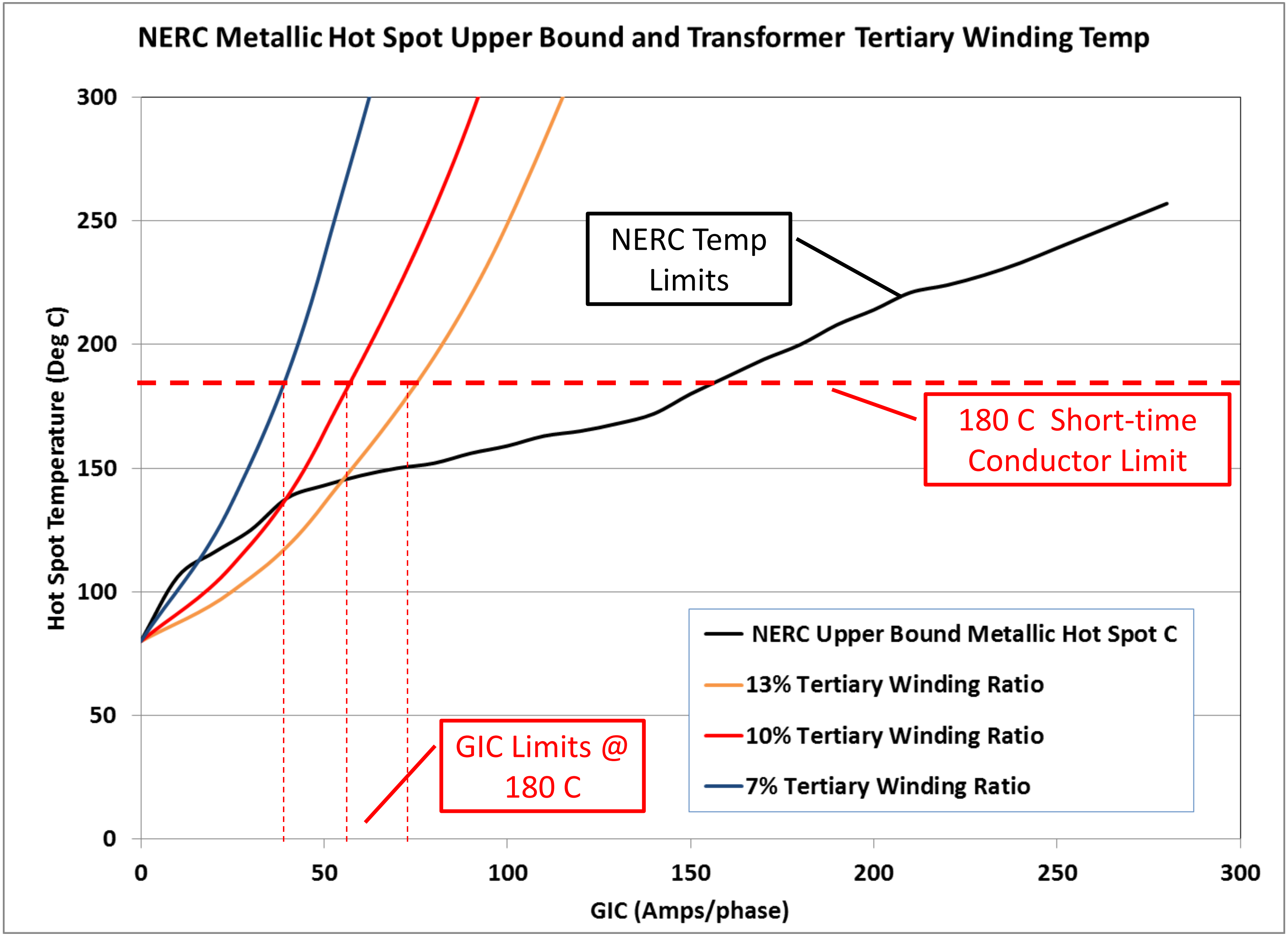


Figure 3 – Plot of NERC Table 1 & Ignored Tertiary Winding Conductor Temperatures



While much of the available monitored GIC and transformer behavior data is being concealed from independent and public review, some small amounts of details have shown heating impacts at lower GIC levels and at higher degrees of severity than the proposed NERC draft standards and screening criteria would anticipate. In reports provided by Allegheny Power, they reported heating and irreversible deleterious impacts at 8 of their 22 EHV 500kV transformers during the March 13, 1989 storm[4]. in subsequent storms where they increased monitoring on an accessible external transformer hot spot revealed by the March 1989 storm, they found significant heating issues that could be confirmed. Figure 4 is a plot of one such observation that occurred during a minor storm on May 10, 1992 at their Meadow Brook 500kV transformer which was a three phase shell form design (again not the most vulnerable transformer design). This plot clearly shows the temperature increasing to ~170 ^{o}C in a matter of just a few minutes for an observed Neutral GIC which peaks out at 60 Amps (equivalent to 20 Amps/phase). Figure 5 provides other data samples of GIC dose and Transformer Heating Response. Again, the GIC is shown in Neutral GIC Amps and needs to be divided by 3 to convert to Amps/phase. As shown, the response is consistent and can therefore also be extrapolated to higher GIC levels[5,6].

This transformer GIC-Exposure / Temperature Response can be contrasted with the Asymptotic thermal response that is included in the NERC Screening Criteria publication. Figure 5 provides a copy of the asymptotic temperature plot (Fig 6 from NERC screening publication) which is now also modified (in red) to show the temperature rise characteristics as actually observed in the Meadow Brook transformer. As this comparison clearly illustrates, the rate of heating is much more severe in the Meadowbrook transformer than what NERC is suggesting is the broad case for all transformers, especially for the large number of existing transformers that were not specifically built or designed to take into consideration any GIC-Tolerance Design Basis.

4. P.R.Gattens, R.M.Waggel, Ramsis Girgus, Robert Nevins,"Investigations of Transformer Overheating Due To Solar Magnetic Disturbances", IEEE Special Publication 90TH0291-5PWR, Effects of Solar- Geomagnetic Disturbances on Power Systems, July12,1989.
5. P. R. Gattens, Robert Langan, " Application of a Transformer Performance Analysis System", presented at Southeastern Electric Exchange, May 28, 1992.
6. Fagnan, Donald A., Phillip Gattens, "Measuring GIC in Power Systems", IEEE Special Publication 90TH0357-4-PWR, July 17, 1990.

Figure 4 – Plot of Observed GIC and Transformer Temperatures at Meadow Brook

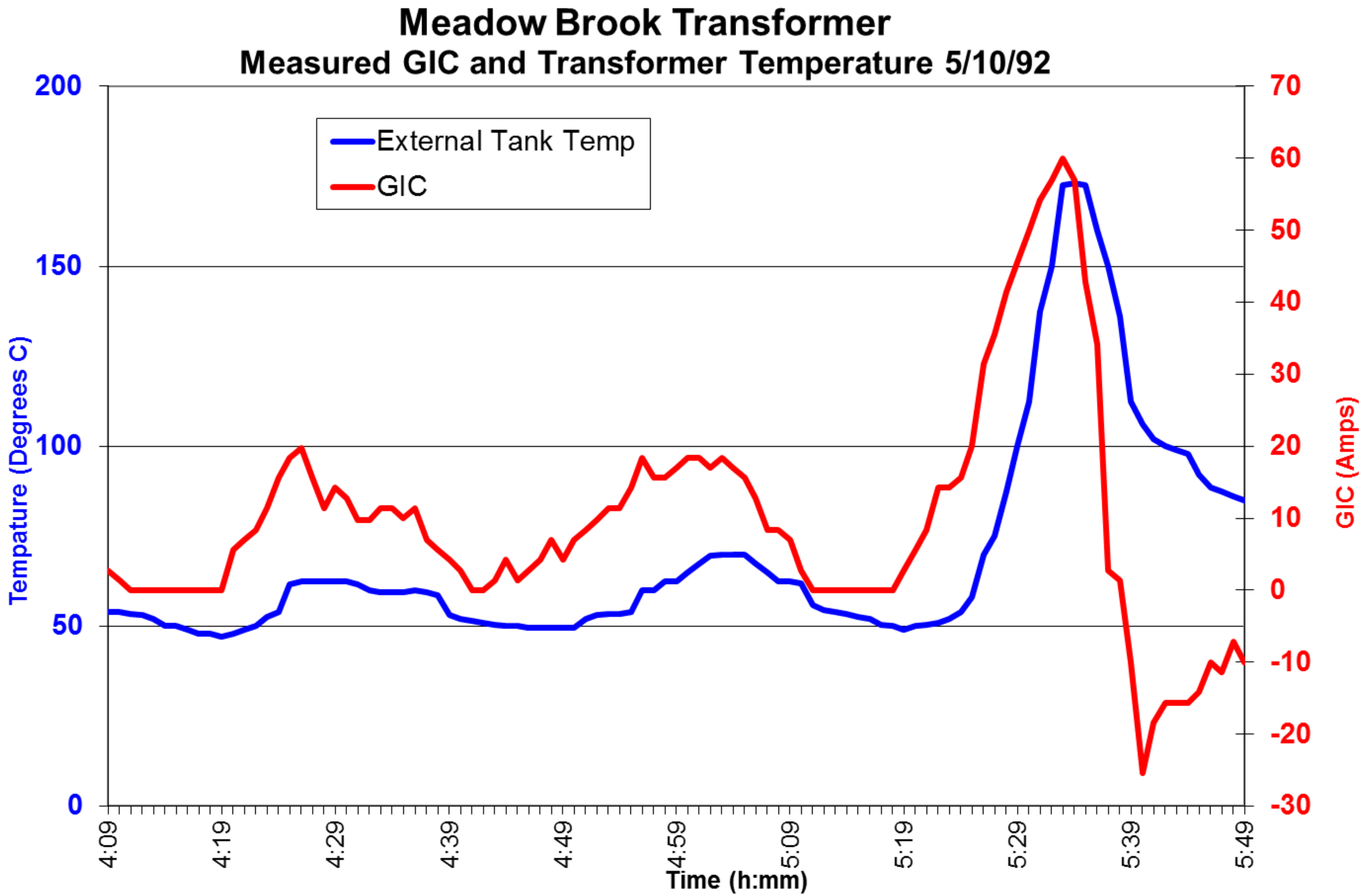


Figure 4 – Plot of Observed GIC and Transformer Temperatures at Meadow Brook

(Note to convert GIC Neutral to GIC Amps/phase, divide by 3)

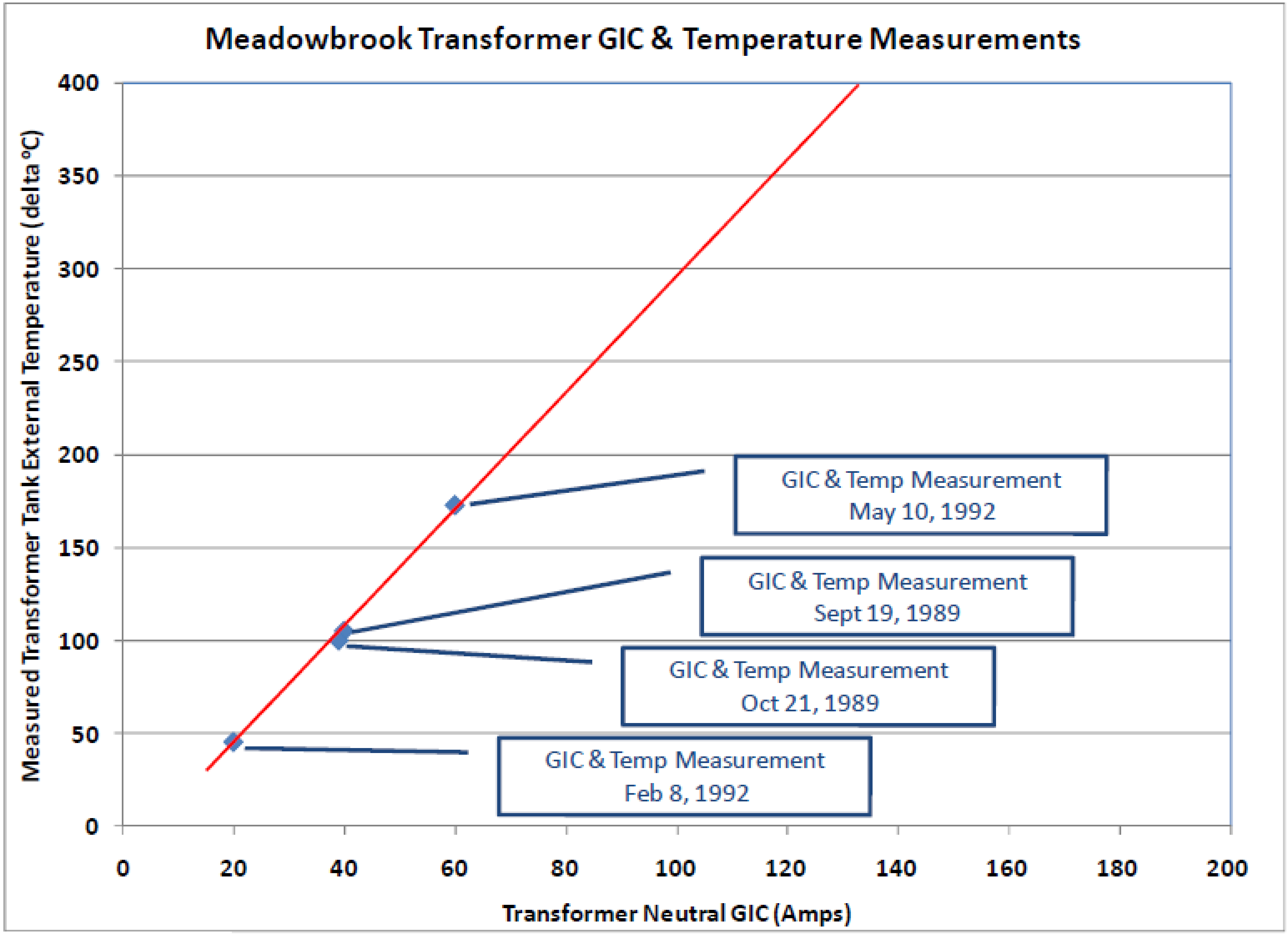


Figure 5-4 - Observation Points of GIC and Hot Spot temperatures and GIC-Temperature Trend Line.

Storm-R-112, August 2011

Figure 5 – NERC Asymptotic thermal response versus Meadow Brook actual

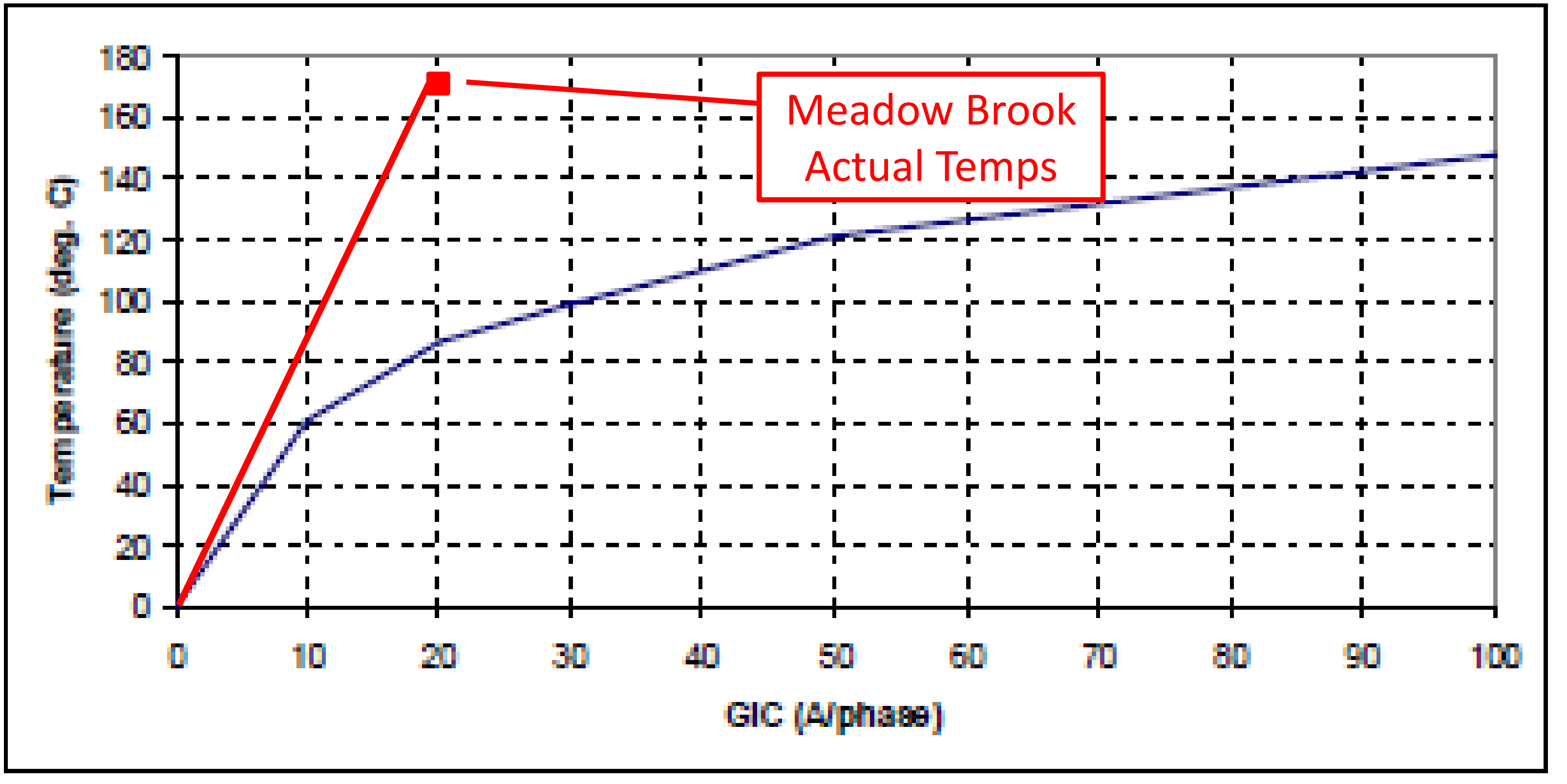


Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

To place the Meadow Brook transformer heating observations in a context that can also be applied to other existing transformers that never had a "GIC Design Basis", it is necessary to review some fundamentals in regards to GIC-caused overheating. The temperature rise experienced in any object (within the transformer and transformer tank) is affected by a number of factors, including:

- Magnitude of the Stray Flux
- Spectral content of the flux
- Magnitude and spectral content of harmonic currents in all windings of the transformer
- Orientation of the flux with respect to the major dimensions of the object
- Dimensions and mass of the object
- Material characteristics (for example permeability, conductivity)
- Heat transfer provided to the object (conduction and oil flow)

In addition to the above factors which relate only to thermal heating impacts, there are a number of other impacts that GIC could cause to a transformer which could damage and shorten its life. These include partial discharge breakdown (something that has been observed, but EPRI and industry have withheld available monitoring data) and also vibrational/mechanical failures to the transformer caused by GIC exposures.

A Brief Overview of Possible Oil Flow Constraints

In these cases and without sufficient oil flow, the temperature rise is capable of approaching ~400^{o}C or higher in a very brief period of time. While the Tank heating at Meadow Brook was associated with a spacer wood slab, the gas in oil analysis also indicated that "acetylene was probably generated by discharges not directly associated with the tank heating"[4]. Oil cooling constraints can arise from other sources, such as cooling triggered via top-oil or simulated hot-spot indicators which will not observe rapid hot-spot developments in unanticipated and very small locations in the transformer due to GIC-caused heating. Electrical Discharging also suggests processes that may still be poorly understood for GIC-exposure concerns.

GIC-caused over excitation of a transformer is an unusual mode of operation and present cooling controls on transformers are not reliably optimized to ensure proper cooling functions within the transformer when a sudden GIC exposure condition develops. For example the turn-on of oil pumps for cooling in many existing transformers is driven by a “simulated hot-spot” not actual hot-spot. The actual hot-spot can be quite different from normal loading when caused by GIC.

In the case of the Meadow Brook transformer a physical obstruction was the cause of oil flow constriction. But for all other exposed transformers, intense hot-spots can develop due to constraints on cooling system limitations as noted here. Therefore these types of existing control systems on transformers cannot be relied upon to ensure adequate oil flow and cooling conditions within the transformer and prevent the rapid transient development of intense hot-spots due to GIC exposures.

A Brief Overview of Tertiary Winding Conductor Heating

The examination of winding heating by the manufacturers and NERC has been limited to only consideration of transformer main windings which have full MVA rating and are much more physically massive than the much reduced MVA Tertiary windings of autotransformers which are also exposed to harmonics generated by the GIC flow in the transformer. Triplen harmonics will naturally circulate in these windings and at low levels of GIC can reach harmonic current levels which greatly exceed their rating leading to enormous losses and heating that is narrowly confined to this very small area within the transformer. Because of the small mass and area involved, it would be reasonable to expect higher temperature rises than noted in the NERC asymptotic charts that have been previously discussed. Further is it unclear whether a lightly load autotransformer which is experiencing a small tertiary winding heating problem would have sufficient oil flow to ensure safety of the winding.

Conclusions

The previous discussions only examined two of the large number of factors that could lead to deleterious impacts to large power transformers exposed to GIC. What has been illustrated in this discussion is the lack of a comprehensive understanding by both the NERC SDT and transformer manufacturers. This has also been coupled with efforts to withhold data and observations taken by the industry and EPRI specifically monitoring transformer impacts during geomagnetic storms. Hence the NERC efforts to increase the GIC safety threshold is being implemented without an adequate examination of all of the possible concerns.

SMARTSENSECOM, INC. COMMENTS ON PROPOSED STANDARD TPL-007-1

In recognition of the potentially severe, wide-spread impact of GMDs on the reliable operation of the Bulk-Power System, FERC directed NERC in Order No. 779 to develop and submit for approval proposed Reliability Standards that address the impact of GMDs on the reliable operation of the Bulk-Power System. In this, the second stage of that standards-setting effort, the Commission directed NERC to create standards that provide comprehensive protections to the Bulk-Power System by requiring applicable entities to protect their facilities against a benchmark GMD event.

In particular, FERC directed NERC to require owners and operators to develop and implement a plan to protect the reliability of the Bulk-Power System, with strategies for protecting against the potential impact of a GMD based on the age, condition, technical specifications, or location of specific equipment, and include means such as automatic current blocking or the isolation of equipment that is not cost effective to retrofit. Moreover, FERC identified certain issues that it expected NERC to consider and explain how the standards addressed those issues. *See* Order No. 779 at ¶ 4. Among the issues identified by FERC was Order No. 779's finding that GMDs can cause "half-cycle saturation" of high-voltage Bulk-Power System transformers, which can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. FERC also found that half-cycle saturation from GICs may severely damage Bulk-Power System transformers. While the proposed standard addresses and explains transformer heating and damage with a model, NERC ignores the issues of harmonic generation and reactive power consumption caused by a GMD event that have caused grid collapse in the past.

FERC has also been very clear to NERC that it considered the "collection, dissemination, and use of GIC monitoring data" to be a critical component of these Second Stage GMD Reliability Standards "because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models." *See* Order No. 797-A, 149 FERC ¶ 61,027 at ¶ 27. However, the proposed standard fails to tie the actions required under the standard to any actual grid conditions. In its place, the proposed standard relies entirely upon an untested system model with several suspect inputs and with no means for model verification and no affirmative requirement for real-time monitoring data as a means to enable GMD mitigation.

It has been nearly eighteen months since Order No. 779 and this comment cycle represents NERC's last opportunity to correct its course before it files TPL-007-1 with FERC. Based on the considerable volume of scientific evidence and the capabilities of modern measurement and control technology to serve as a mitigation method, the proposed standard is technically unsound and fails to adequately address FERC's directives. Rather than risk the operation of the grid on the perfection of an untested model, NERC should have provided requirements for the collection and dissemination of GMD information, such as data collected from real-time current and harmonic monitoring equipment, to ensure that the Bulk-Power System is able to ride-through system disturbances. NERC should include these measures in TPL-007-1 or be prepared for a likely FERC remand – leaving the Bulk-Power System exposed to the risk of GMD while NERC addresses the matters that it ought to have considered at this stage of the process.

1. TPL-007-1 Should be Modified to Account for the Impact of System Harmonics and VAR Consumption and Mitigate the Risk Created by Reliance On Untested System Models

In Order No. 779, FERC found that GMDs cause half-cycle saturation of Bulk-Power System transformers, which can lead to transformer damage, increased consumption of reactive power, and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System. Whereas TPL-007-1 takes pains to model transformer thermal heating effects, the proposed standard does not adequately address the risks posed by harmonic injection and VAR consumption. Failure to deal directly with the effects of harmonics and VAR consumption is irresponsible given the empirical evidence of their impact upon system reliability during GMD events. Real-time monitoring, as called for by FERC, would provide the real-time operating information necessary to account for – and mitigate – these negative system effects. Real-time monitoring information would also remedy the vulnerability created by standard's "model-only" approach to the GMD threat and provide a means to iteratively improve any model over time.

A. Failure to Account for Harmonics and VAR Consumption

In the presence of a GIC, a saturated transformer becomes a reactive energy sink, acting as an unexpected inductive load on the system, and behaves more like a shunt reactor.

Consequently, transformer differential protective relays may trip and remove the transformer from service because of the disproportionately large primary current being drawn and consumed by the saturated transformer. System VAR support devices, such as capacitor banks and SVCs, become particularly critical during such conditions in order to offset the undesired behavior of GIC-affected transformers. The magnetizing current pulse of a GIC-inflicted transformer injects substantial harmonics into the power system.

VAR support devices are a low impedance path for harmonic currents and subsequently these devices begin to draw large currents too. A power flow "tug-of-war" ensues between the saturated transformers and VAR support devices. The sustenance of the VAR support devices is paramount as their failure may result in system voltage instability and collapse. However, harmonics doom these devices on multiple counts. For example, the large harmonic currents being consumed by capacitor banks may affect other components in the device that cannot withstand such high magnitude currents and result in damage and the unwanted tripping of the capacitor bank. Additionally, harmonics often result in the improper operation of protective equipment, such as overcurrent relays. Therefore, harmonics are ultimately predisposing system VAR support components to failure and increasing the vulnerability of the grid to voltage instability and collapse. See Duplessis, *The Use of Intensity Modulated Optical Sensing Technology to Identify and Measure Impacts of GIC on the Power System* (attached).

Accounting for GIC-related harmonic impacts is also essential considering that where GICs have caused significant power outages, harmonics have been identified as the primary system failure mode through the improper tripping of protection relays in known GMD events. For example, the 1989 Quebec blackout was traced to improper protective device tripping influenced by the GIC-induced where seven large static VAR compensators were improperly tripped offline by relays. See Department of Homeland Security, *Impacts of Severe Space Weather on the Electric Grid*, Section 4.4. In light of FERC's directive to address and explain how the standard address these issues, it is clear that TPL-007-1 be modified to directly account for the reactive power and harmonic effects of GMD events.

B. Over-Reliance on Untested Models

The core of the proposed standard is a series of models designed to approximate the "worst-case" scenarios of a GMD event which are, in turn, used to determine system vulnerability and whether corrective action is required. This "model-only" approach is technically insufficient and leaves the grid open to unnecessary risk. Moreover, no mechanism exists in the standards to validate the GMD models through the use of actual operating data.

First, genuine concerns exist regarding whether the "worst-case" GMD scenario is actually being modeled or whether the model substantially underrepresents the threat. For example, according to empirically-based arguments of John Kappenman and William Radasky in their White Paper submitted to the NERC earlier this year, the NERC Benchmark model under-estimates the resulting electric fields by factors of 2x to 5x. Kappenman *et al*., *Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard*. The thermal heating model also relies upon a 75 amps <u>per phase</u> assumption (equivalent to total neutral GIC of 225 amps) as the modeled parameter. As shown in the Oak Ridge Study, it was found that at as little as 90 amps (or 30 amps per phase) there is risk of permanent transformer damage. *See, e.g.*, Oak Ridge National Laboratory, FERC EMP-GIC Metatech Report 319 at 4-8 ("Oak Ridge Study"). Indeed, the Oak Ridge Study found that a 30 amps per phase level is the approximate GIC withstand threshold for the Salem nuclear plant GSU transformer and possibly for others of similar less robust design in the legacy population of U.S. EHV transformers. *See* Oak Ridge Study at Table 4-1 (finding 53% of the Nation's 345kV transformers at risk of permanent damage at a 30 amps <u>per phase</u> GIC level). In addition, the system model specified in Requirement 2 should also be run on the assumption that all VAR support components on the system (e.g., capacitor banks, SVCs, etc.) become inactive (i.e., removed from service by undesired operation of protective devices caused by the harmonics that GIC affected transformers are injecting into the system).

That the models appear to substantially under-estimate the expected GMD impact is critical as it the models alone – under the proposed standard – that drive the vulnerability assessments and corrective action plans that require owners and operators to implement appropriate strategies. As written, these models have the effect of greatly reducing the scope of the protective requirements that will be implemented, potentially allowing sizable portions of the grid to be wholly unprotected and subject to cascading blackouts despite the adoption of standards. The extensive analysis and findings of the Kappenman-Radasky White Paper and the Oak Ridge Study suggest that the modeling approach elected by NERC is technically unsound, does not accurately assess a "worst case" scenario as it purports to do, and, in any event, should not be the sole basis for the standard's applicability.

Second, the proposed standard provides no means to validate or update the standard's models in light of actual operating data. This amounts to little more than a gambler's wager that the model will adequately protect the Bulk-Power System from a substantial GMD event, when it has never actually been tested. As the model is designed, actual operating data has no means to influence or override actions based upon the model. This is inappropriate. As discussed above, it is likely that the model developed will underestimate the effects of a GMD event. To rely on a model to simulate actual equipment performance over a range of potential GMD disturbances, it is essential that that model must not only contain adequate information (i.e. – an accurate up-front estimate), but that it must also correspond to actual reported field values. NERC should modify the standard to provide that actual operating data be used to regularly verify and improve the model.

C. The Solution – Collect, Disseminate, and Use Real-Time Reactive Power and Harmonic Content Information to Mitigate GMD Impacts

While the standard's model-based approach to GMD mitigation efforts may have some limited utility as a first step towards identifying vulnerabilities and developing forward-looking correction action plans, the standard would provide far better protection with a requirement for the collection and use of accurate, real-time data regarding current, reactive power consumption, and system harmonics. Real-time data should underpin any GMD mitigation efforts, substantially reducing the risk of outages and damage to critical equipment in the event of a GMD, and would also improve the reliability of system models. Modern grid measurement and control technologies are capable and readily deployable to mitigate GMD events.

First, real-time monitoring enables protective devices to be efficiently managed during a GIC event, initiating control signals that enable devices to “ride-through” GMD where they may otherwise trip offline during a period of normal operation. In these instances, the detection of harmonic content could be used to sense transformer saturation and override normal protective device trip settings in order to maintain key equipment online and not be “fooled” into tripping by the harmonics generated by the event. Given the diversity of protective devices for equipment used throughout the Bulk-Power System, a technically preferable approach would be to actively manage protection schemes based upon real-time operating data. Regarding the system’s VAR response, if system voltage becomes unstable when VAR support is inhibited during a GIC event, operators would have an available solution through the identification of atypical harmonics, which can be associated with a GIC event, and this information used as a trigger to implement alternate protective schemes for VAR support components for the duration of the GIC event.

Second, if a GMD event is detected through the monitoring of systemic VAR consumption and harmonic content at key points in the network (which may include current monitoring on vulnerable transformer neutrals and monitoring of harmonics and VAR consumption on phases), this real-time monitoring data could be used to draw down, and ultimately cease, GMD operating procedures as the GMD event passes. Moreover, the VAR and harmonic derived from real-time operation information may also be used to trigger operating procedures, which is necessary given that the existing operational standard relies on space weather forecasts as the trigger for the implementation of operating procedures, despite the substantial error rates associated with these forecasts. Since GMD procedures impose transmission constraints that do not permit wholesale energy markets or system dispatch to achieve the most efficient use of available resources, ultimately affecting the prices paid by consumers, NERC should seek to minimize the frequency and duration of mitigation efforts. Real-time monitoring of harmonic content and reactive power would enable a more efficient approach to recognizing and reacting to GMD events, harmonizing the Phase I and Phase II standards and providing greater overall protection to the grid.

Further, real-time monitoring information must be used to validate models that are used to inform the means by which owners and operators will prepare for, and react to, GMD events. Currently, the models presented in the standard are the sole means to trigger the implementation of protection measures and the availability of actual operating data that questions the model's outputs have no means to override the model-based approach. The use of actual operating data to verify the standard's model would improve the accuracy of model verifications needed to support reliability. A better approach would be to use modeling and real-time monitoring in tandem to constantly verify and enhance the model, while still maintaining protections for "missed" events that the model is likely to inevitably overlook. The people of the United States should not have the ongoing Bulk-Power System reliability put at risk by an unverified model.

NERC should use its authority to insure that real operating data will, over time, be employed to verify and improve any reference model and that real operating data will be employed as a means to ensure ongoing system reliability when events render the reference model unequal to its protective task (which evidence suggests will happen). The proposed standard should be modified to require the collection, dissemination, and use of real-time voltage and current monitoring data which will provide the reactive power and harmonic content information necessary to effectively and efficiently manage the system in response to GMDs.

2. Conclusion

FERC was clear in its direction to NERC that the collection, dissemination, and use of real-time GIC monitoring data was a critical component of these Second Stage GMD Reliability Standards "because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models." See Order No. 797-A, 149 FERC ¶ 61,027 at ¶ 27. FERC also was clear that harmonic content and reactive power consumption created by GMD events constituted serious threats to system reliability that must be addressed. Order No. 779 at ¶ 7. The draft standard offered by NERC simply fails to meet the needs identified by FERC – which are amply supported by the record established in these proceedings – a reasonable person could reach no other conclusion.

To create a reasonable and prudent standard, NERC needs to address the reactive power and harmonic generation aspects of GMD events, and it needs to provide for verification and improvement of the model included in the draft standard. The only route to meeting those needs that is supported by the evidentiary based findings and FERC's directives is a mandate for the collection, dissemination, and use of real-time GIC current and harmonic data to drive protection schemes. With clearly articulated requirements for such data, NERC can fill the gaps in the current standard and provide a means by which to adequately protect the Bulk-Power system.

Respectfully submitted,

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SmartSenseCom INCORPORATED

The Use of Intensity Modulated Optical Sensing Technology to Identify and Measure Impacts of GIC on the Power System

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Abstract

This paper describes the phenomenon of geomagnetically induced currents ("GIC"), a geomagnetic disturbance's potential impact on transformers and the electric power system, and FERC/NERC regulation regarding utility responsibility. The paper then introduces intensity modulated optical sensing technology, explains how this technology has been adapted to measure voltage, current, phase and other characteristics of electric phenomena, and answers why this adaptable core technology provides a comprehensive solution to identifying and measuring the impacts of GIC.

Introduction

The phenomenon of geomagnetically induced currents ("GIC") has been well documented[1] and is summarized herein. Because of the catastrophic impacts a major solar storm, which precipitates GIC flow, can have on electric power grid operations and its components, the Federal Energy Regulatory Commission (FERC) issued an order in May 2013 requiring the North American Electric Reliability Corporation (NERC) to create reliability standards to address the Geomagnetic Disturbance (GMD) threat.

This paper reviews the mechanism by which the loss of reactive power occurs due to GIC and how it could lead to system voltage collapse, which is central to FERC's concerns. However, the main impetus for writing this paper is to introduce a technology that brings true system visibility within reach of utility asset managers and system operators. This visibility is paramount to the success of managing GIC effects. Practically, it is impossible to manage something you cannot measure; for example, how can you know whether the reaction is appropriate for the problem if the latter is not quantified? Increased system visibility also validates the effectiveness of strategies to block GIC.

Managing and blocking are the two mitigation approaches for dealing with GIC. Managing GIC in real time involves fast, responsive operating procedures. While modeling efforts will aid in predetermining operating steps that will help to minimize outages and limit damage to critical equipment in the presence of GIC, accurate, real-time system visibility reveals the necessity of these operating steps or need for more during each unique GMD event and guides the operator (manual or automatic) with respect to when these steps must be implemented (and when the danger is gone). Afterwards, this increased visibility will help improve the predefined thresholds of system switching and VAR support components used during GIC induced events.

Alternatively, blocking GIC can be done through several means, including the installation of a GIC neutral blocking capacitor on the neutral of a susceptible transformer, resistive grounding of the transformer

[1] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013, references.

(although this will require a higher surge arrester rating), and series capacitor blocking in transmission lines.

The technology that delivers the system visibility required to effectively manage and mitigate the threat of GMD is called Intensity Modulated ("IM") Optical Sensing. It was developed by the Naval Research Laboratory for use by the United States Navy in mission-critical applications which presented with very hostile measuring environments. IM optical sensing devices solve the measuring challenges to which other optical devices and traditional instrument transformer devices succumb, including those present during geomagnetic storms. Furthermore, the measuring capabilities of IM optical sensing devices transcend the capabilities of traditional devices. The remarkable stability of an IM optical monitoring systems in harsh measuring conditions, its higher accuracy, broadband measuring capabilities, and its real-time delivery of power system information are key to delivering a more resilient electric power grid, even and particularly in the grips of such High Impact Low Frequency events as GMD.

Geomagnetically Induced Currents

Geomagnetic storms are associated with activity on the sun's surface, namely sunspots and solar flares. Solar flares result in electromagnetic radiation (coronal mass ejections (CME), x-rays and charged particles) forming a plasma cloud or "gust of solar wind" that can reach earth in as little as eight minutes. Depending on its orientation, the magnetic field produced by the current within this plasma cloud can interact with the earth's magnetic field, causing it to fluctuate, and result in a geomagnetic storm.

Geomagnetically induced currents ("GICs") are caused when the "auroral electrojet", currents that follow high altitude circular paths around the earth's geomagnetic poles in the magnetosphere at altitudes of about 100 kilometers, becomes 'energized' and subjects portions of the earth's nonhomogeneous, conductive surface to slow, time-varying fluctuations in Earth's normally unchanging magnetic field. [1][2] By Faraday's Law of Induction, these time-varying magnetic field fluctuations induce electric fields in the earth which give rise to potential differences (ESPs – earth surface potentials) between grounding points. The distances over which a resulting electric field's effects may be felt can be quite large. The field, then, essentially behaves as an ideal voltage source between rather remote neutral ground connections of transformers in a power system, causing a GIC to flow through these transformers, connected power system lines and neutral ground points.

A power system's susceptibility to geomagnetic storms varies and is dependent upon several contributing elements, including:

- The characteristics of the transformers on the system, which serve as the entry (and exit points) for GIC flow, such as:
    - Transformer winding construction: Any transformer with a grounded-wye connection is susceptible to having quasi-DC current flow through its windings; an autotransformer (whereby the high- and low-voltage windings are common, or shared) permits GIC to

[2] John G. Kappenman, 'Geomagnetic Disturbances and Impacts upon Power System Operation,' The Electric Power Engineering Handbook, Chapter 4.9, 4-151., 2001.

pass through to the high-voltage power lines, while a delta-wye transformer does not [Figure 1].

- Transformer core construction: The core design determines the magnetic reluctance of the DC flux path which influences the magnitude of the DC flux shift that will occur in the core. A 3-phase, 3-legged core form transformer, with an order of magnitude higher reluctance to the DC Amp-turns in the 'core – tank' magnetic circuit than other core types, is least vulnerable to GIC. Most problems are associated with single phase core or shell form units, 3-phase shell form designs or 3-phase, 5-legged core form designs.[3]
- Transformer ground construction: Transformers on extra high voltage (EHV) transmission systems are more vulnerable than others because those systems are very solidly grounded, creating a low-resistive, desirable path for the flow of GIC. Incidentally, many EHV transformers are not 3-phase, 3-legged core form designs.

- The geographical location, specifically the magnetic latitude, of the power system: The closer the power segment is to the earth's magnetic poles generally means the nearer it is to the auroral electrojet currents, and consequently, the greater the effect.[4] Note, however, that the lines of magnetic latitude do not map exactly with geographic latitude as the north and south magnetic poles are offset from Earth's spin axis poles. Therefore, the East coast geographic mid-latitude is more vulnerable than the West coast geographic mid-latitude as the former is closer to the magnetic pole.[4]
- Earth ground conductivity: Power systems in areas of low conductivity, such as regions of igneous rock geology (common in NE and Canada), are the most vulnerable to the effects of intense geomagnetic activity because: (1) any geomagnetic disturbance will cause a larger gradient in the earth surface potential it induces in the ground (for example, 6 V/km or larger versus 1 – 2 V/km)[5] and (2) the relatively high resistance of igneous rock encourages more current to flow in alternative conductors such as power transmission lines situated above these geological formations (current will utilize any path available to it but favors the least resistive).[5] Earth's conductivity varies by as much as five orders of magnitude. [5] [Reference Figure 2.]
- Orientation of the power system lines (E-W versus N-S): The orientation of the power lines affects the induced currents. The gradients of earth surface potential are normally, though not always, greater in the east-west direction than in the north-south direction.[6]
- The length and connectivity of the power system lines: The longer the transmission lines the greater the vulnerability. Systems dependent upon remote generation sources linked by long transmission lines to deliver energy to load centers are particularly vulnerable. This is characteristic of Hydro Quebec's system in Quebec where much of its power is produced far from where it is consumed; for example, its James Bay generators are 1,000 km away from any

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[3] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.
[4] James A. Marusek, "Solar Storm Threat Analysis", Impact 2007, Bloomfield, Indiana
[5] John G. Kappenman, 'Geomagnetic Disturbances and Impacts upon Power System Operation,' The Electric Power Engineering Handbook, Chapter 4.9, 4-151., 2001.
[6] P.R. Barnes, D.T. Rizy, and B.W. McConnell, "Electric Utility Experience with Geomagnetic Disturbances," Oak Ridge National Lab, Nov. 25, 1991.

populated load center.[7] Since the GMD event that ravished their system in March 1989, Hydro Quebec has installed series capacitors on transmission lines which will block GIC flow.

- The strength of the geomagnetic storm: A more powerful solar storm increases the intensity of the auroral electrojet currents and can move these currents towards the earth's equator.

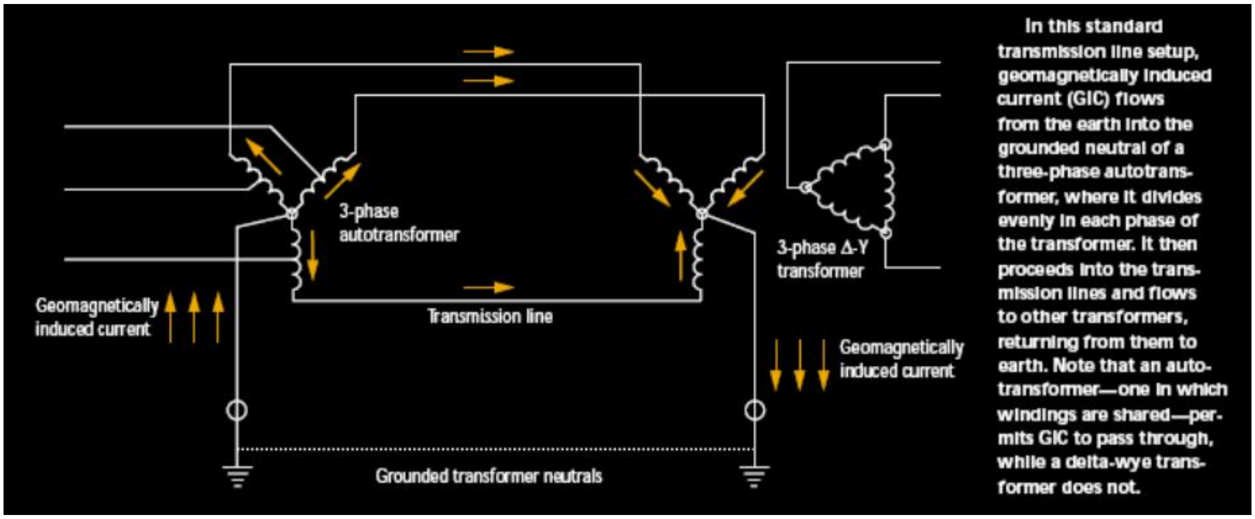

FIGURE 1
Conducting Path for GICs[8]

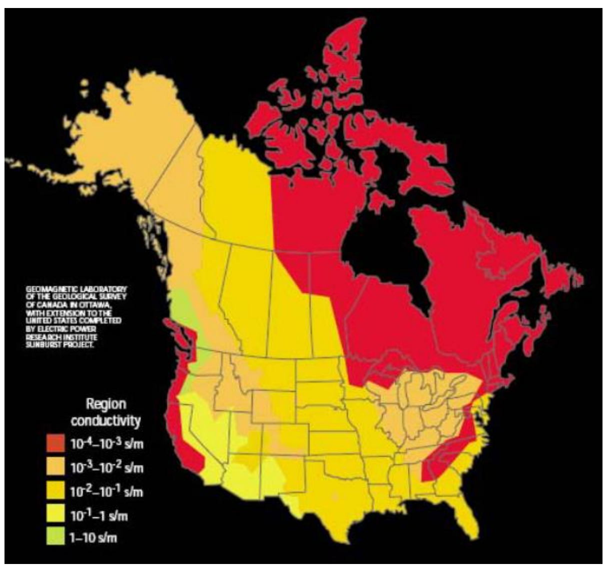

FIGURE 2
Earth Conductivity in US & Canada[8]

[7] M. Corey Goldman, "How one power grid kept lights on", Toronto Star, September 8, 2003, http://www.ontariotenants.ca/electricity/articles/2003/ts-03i08.phtml

[8] Tom S. Molinski, William E. Feero, and Ben L. Damsky, "Shielding Grids from Solar Storms", *IEEE Spectrum*, November 2000, pp. 55-60.

The impact of GIC on afflicted transformers and corresponding electric power systems is generally understood but the many variables that influence vulnerability and therefore the inconsistency in the resultant singular manifestations of GIC lends to a near impossible cumulative quantification of a geomagnetic storm's impact on power systems. Most impact quantifications up to now have been anecdotal.

Potential Impact of GIC on Transformers and Electric Power Systems

The source of nearly all of the operating and equipment problems attributed to a geomagnetic disturbance is the reaction of susceptible transformers in the presence of GIC. Therefore, the first order effects of GIC are those on the transformer and the second order effects of GIC are those on the power system.

First Order Effects of GIC

The exciting current of a transformer represents the continuous energy required to force "transformer action", in other words, make the transformer behave as a transformer. It is largely a reactive current (usually dominated by an inductive contribution known as the magnetizing current) and typically very small as transformers are very efficient devices, usually less than 1% of the transformer's rated operating current. Under normal, steady state conditions, the exciting current of a transformer is symmetrical (balanced between the positive and negative peaks of its waveform) as shown in Figure 3; the exciting current is shown in blue on the bottom vertical axis.

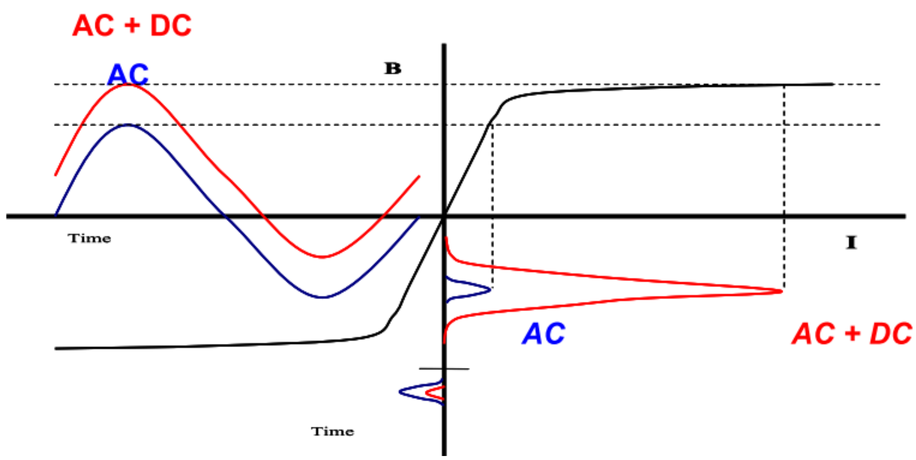

FIGURE 3
Part Cycle, Semi Saturation of Transformer Cores[9]

For economic motivations, the peak ac flux in the power transformer (given by the blue waveform on the left side of Figure 3) is designed to be close to the knee (or magnetic saturation point) of the magnetization curve (shown by the black curve in Figure 3) so that nearly the full magnetic capabilities of the transformer's core is used during operation. When a core operates below its saturation point, practically all of the magnetic flux created by the exciting current is contained in the core. The magnetic reluctance of the core is low because the core steel is an excellent conduit for magnetic flux.

[9] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.

Accordingly, the magnetization losses are low (i.e., a small I_h in Figure 4) and the (shunt) magnetizing inductance is high, resulting in a very small magnetizing current, I_m. The exciting current is the vector sum of these current contributions, I_h and I_m. The inductive volt-amperes-reactive (VAR) requirements of the transformer are very low. Moreover, with non-saturated core magnetization, the transformer voltage and current waveforms contain very low harmonic content.

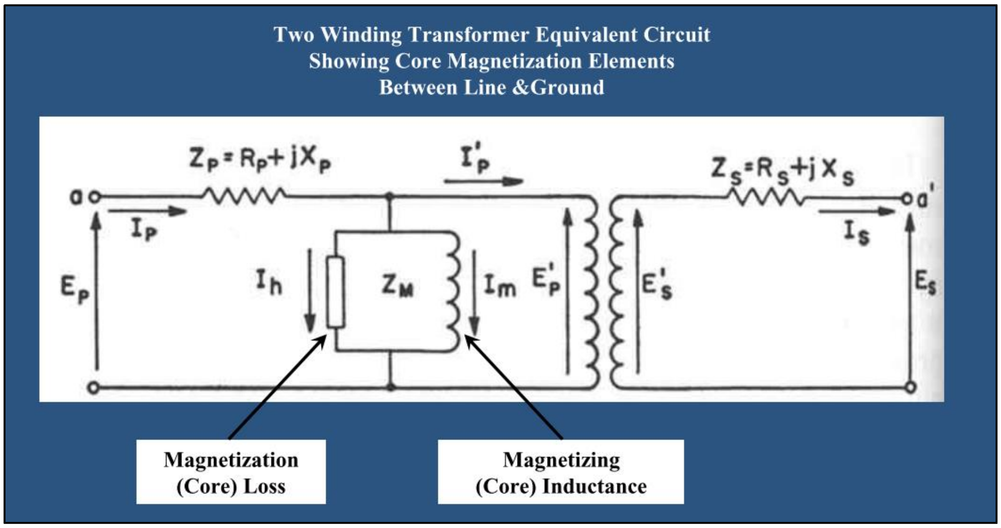

FIGURE 4
Transformer Equivalent Circuit[10]

During a GIC event, a quasi-dc current enters the ground connected neutral of the transformer and splits equally between phase windings (on multiple phase winding transformers). If the zero sequence reluctance of the transformer is low, the GIC biases the operating point on the magnetization curve to one side (see the top black dashed line in Figure 3). This bias causes the transformer to enter the saturation region in the half cycle in which the ac causes a flux in the same direction as the bias. This effect is known as half-cycle saturation.[11] When the core saturates, it has reached the limit of its ability to carry a magnetic field and any field beyond the limit "leaks" out of the core and passes through the space around the core (air/oil) as "leakage flux". While the magnetic reluctance of the core is still low, the reluctance of the portion of the magnetic circuit outside the core is high. This results in a much-lowered value of shunt inductance and a large shunt current (I_m) flows through the magnetizing branch. The inductive volt-amperes-reactive (VAR) requirements of the transformer can become very high (see the red exciting current pulse given a DC offset on the bottom vertical axis in Figure 3). With saturated core magnetization, the transformer voltage and current waveforms contain very high harmonic content.

[10] W. Hagman, "Space Weather in Solar Cycle 24: Is the Power Grid at Risk?", IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[11] W. Chandrasena, P.G. McLaren, U.D. Annakkage, R.P. Jayasinghe, "Modeling GIC Effects on Power Systems: The Need to Model Magnetic Status of Transformers", 2003 IEEE Bologna Power Tech Conference, June 23 – 26, 2003, Bologna, Italy

Problems can occur with differential protective relays that are looking to see balanced primary and secondary currents, i.e., the transformer may trip as the primary current becomes disproportionately large (drawing increasingly more reactive current) compared to its secondary current.

Leakage flux is always present in a transformer that is carrying load. Because of the problems that it can otherwise cause, transformer manufacturers design and build their transformers such that the anticipated leakage flux is "managed" and has minimal impact on the long term operation and survivability of the transformer. Leakage flux, however, is never anticipated from the excitation of the transformer. The high peak magnetizing current pulse (red in Figure 3) produces correspondingly higher magnitudes of leakage flux (as given by the red waveform on the left side of Figure 3) that is also rich in harmonics.[12]

The influence of excessive leakage flux on the transformer is generally thermal. Leakage flux in transformers that links any conductive material (including transformer windings and structural parts) will cause induced currents which will result in almost immediate localized, unexpected, and severe heating due to resistive losses. Paint burning off transformer tank walls might be considered an asset owner's best news case example. Transformer designs that implement core bolts are a concern because should the stray flux link such bolts located at the bottom of the windings and cause the surrounding oil to heat to 140°C, this could result in bubble evolution that ultimately fails the transformer. For any given design, a finite element analysis will reveal the leakage flux paths and weaknesses, if any, in the design. If a transformer is lightly loaded, and therefore its operating leakage flux is light as compared to its full load rated flux, the unit may be able to handle the additional leakage flux introduced by GIC.

In summary, a saturated transformer becomes a reactive energy sink, an unexpected inductive load on the system, and behaves more like a shunt reactor.[13] Transformer differential protective relays may trip and remove the transformer from service. Excessive leakage flux can result in detrimental overheating, or in some designs, winding damage due to resulting high winding circulating currents. Separately, the magnetizing current pulse of a GIC inflicted transformer injects significant harmonics into the power system. The resultant impact of these changes in the transformer(s) constitutes the second order effects of GIC.

<u>Second Order Effects of GIC</u>

Many agree that the more concerning impacts of GIC are its indirect effects on the power system and its components. The influence of a transformer morphing into a shunt reactor on the power system is best understood after a review of shunt reactors and capacitors.

Shunt capacitor banks are used to offset inductive effects on the power system (to support voltage) while shunt reactors are used to offset the effects of capacitance on the system (to lower voltage). Typically, shunt capacitors are switched in during periods of high load, and shunt reactors are switched in during periods of light load. The same effects can be achieved, within rating limits, by varying the excitation of generators, i.e., operating them as "synchronous condensers". Static VAR compensators (SVC's), which combine capacitor banks and reactors also provide similar compensation and voltage

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[12] R. Girgis and K. Vedante, "Effects of GIC on Power Transformers and Power Systems," 2012 IEEE PES Transmission and Distribution Conference and Exposition, Orlando, FL, May 7-10, 2012.

[13] It should be noted that upon removal of the DC current, a core will not remain in its saturated state while energized.

support, with very fast automated controls. Many power systems once had dedicated synchronous condensers (rotating machines). However, capacitor banks are cheaper and capacitor technology advanced to the point where reliability became excellent, so synchronous condensers were retired.[14]

Inductive reactance, which is expressed by, $X_L = 2\pi fL$, indicates that as inductance, L, goes down, inductive reactance drops. Saturated transformers have low shunt magnetizing inductance so they draw high currents; they look like shunt reactors on the system, dragging down the system voltage. Capacitive reactance is expressed by, $X_C = 1/(2\pi fC)$. From this, it is easy to see that a capacitor presents as an open circuit (infinite impedance) to DC current; thus the effectiveness of series capacitor blocking in very long transmission lines as a GIC mitigation strategy. Alternatively, as frequency goes up, capacitive reactance drops so capacitor banks have lower impedances to harmonics and draw larger currents when harmonics are present.

While saturated transformers draw large currents, forcing system voltage down (and potentially overloading long transmission lines), capacitor banks also draw large currents due to the presence of resultant harmonics, partially offsetting the inductive effects. Essentially, the saturated transformers are in a tug-of-war with the capacitors on the system. Modern shunt capacitors have very low loss and are therefore less susceptible to transient heating damage due to excess current. However, large currents may affect other components in capacitor bank installations, resulting in damage and unwanted tripping.[15] Voltage imbalance and overvoltage protection may also be “fooled” by harmonic voltage spikes and cause unwanted trips. Finally, overcurrent protection may also operate spuriously in the face of harmonic currents.[16] Similar issues may apply to SVC’s. Harmonic filters for SVCs banks create parallel resonances which can exacerbate voltage disturbance issues and result in tripping of the protection devices. [13]

Rotating machines have fairly high thermal inertias, so generators operated as synchronous condensers have a higher probability of staying on line.[13] However, generators can also be affected by GIC currents. These effects include additional heating, damage to rotor components, increased mechanical vibrations and torsional stress due to oscillating rotor flux caused by increased negative sequence harmonic currents. The harmonic content of negative sequence currents can also cause relay alarming, erratic behavior or generator tripping.[17] If VAR resources are exhausted during a GMD event, specifically capacitive voltage support, voltage collapse can occur.

NERC’s 2012 Special Reliability Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System provides a block diagram that illustrates the effects of GIC, culminating in a threat to system voltage and angle stability (Figure 5).

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[14] W. Hagman, “Space Weather in Solar Cycle 24: Is the Power Grid at Risk?”, IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[15] W. Hagman, “Space Weather in Solar Cycle 24: Is the Power Grid at Risk?”, IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

[16] B. Bozoki et al., Working Group K-11 of the Substation Protection Subcommittee of the Power System Relaying Committee, IEEE PES, “The Effects of GIC on Protective Relaying,” *IEEE Transactions on PowerDelivery*, Vol. 11, No. 2, April 1996, pp. 725-739.

[17] D. Wojtczak and M. Marz, “Geomagnetic Disturbances and the Transmission Grid” http://www.cce.umn.edu/documents/cpe-conferences/mipsycon-papers/2013/geomagneticdisturbancesandthetransmissiongrid.pdf

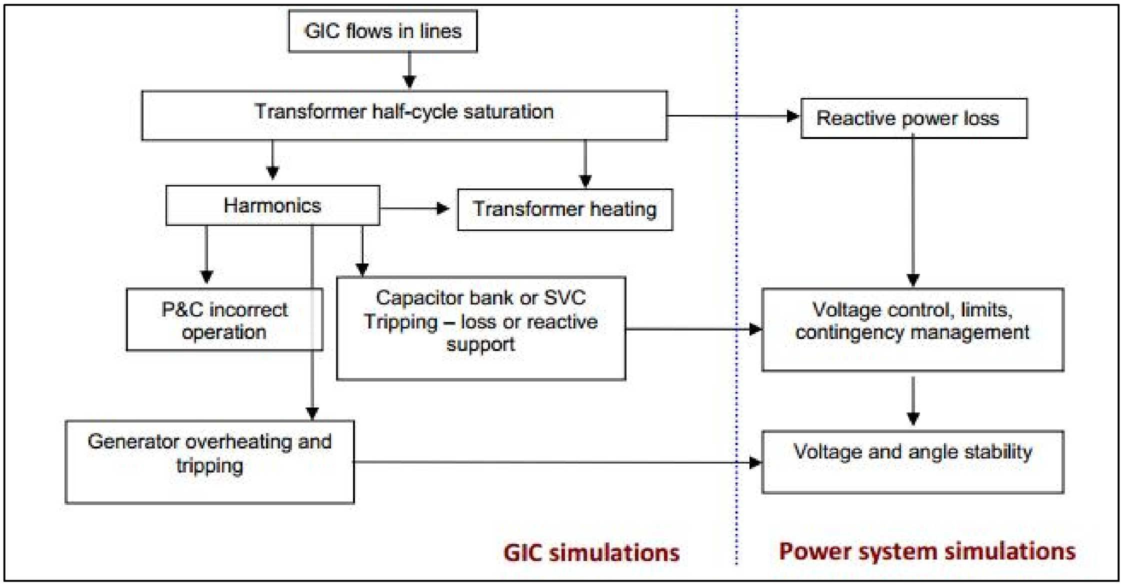

FIGURE 5
From NERC: Effects of GIC in a High Voltage Transmission Network[18]

<u>A Special Dispensation about the Effects of GIC on CTs (and protective relays)</u>;

It is important to have accurate measurements of system state during abnormal operating conditions. For these purposes, the industry has predominantly relied upon conventional instrument transformers (such as a current transformer ("CT"); a potential (or voltage) transformer, which may be inductive ("PT"/"VT") or capacitive ("CCVT"); or a combined current and voltage instrument transformer). An instrument transformer ("IT") is "intended to reproduce in its secondary circuit, in a definite and known proportion, the current or voltage of its primary circuit with the phase relations and waveforms substantially preserved."[19] The electromagnetically induced current or voltage waveform(s) in the secondary circuit(s) of the instrument transformer (IT) should then be of an easily measurable value for the metering or protective devices that are connected as the load, or "burden", on the IT.

In as much as a traditional, "ferromagnetic" IT has a magnetic core, instrument transformers are subject to influence from the presence of GIC much like a power transformer (discussed in the preceding sections). If an IT is pushed to a non-linear region of its saturation curve (i.e., its operating curve), due, for example, to a DC flux shift, the accuracy of the IT will significantly decline. While it is true that ITs typically operate at lower magnetization levels than power transformers because reading accuracy must be maintained in the face of large fault currents (i.e., they have more "built-in margin" on the curve), there is no way of knowing whether the magnitude of GIC in the system is yet enough to saturate the core (despite its margins), or if remanence was pre-existing in the core and already compromising the IT's performance. In short, there will always be uncertainty about the reliability of system state measurements provided by ferromagnetic instrument transformers during a GIC event. Moreover,

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[18] North American Electric Reliability Corporation (NERC) Geomagnetic Disturbance Task Force (GMDTF) Interim Report, "Effects of Geomagnetic Disturbances on the Bulk Power System," February 2012, page 62. http://www.nerc.com/files/2012GMD.pdf

[19] "C37.110-2007 IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes", IEEE, New York, NY April 7, 2008.

when currents and voltages become rich in harmonics, even if the IT is not operating in a saturated state, the accuracy of the measurements will decline. Unfortunately, there is no on-line method of validating whether the instrument transformer is operating in a non-saturated state and, therefore, within its “window of accuracy” (i.e., the pseudo-linear region of its saturation curve at 60 Hz) or in a saturated state and, therefore, outside the realm in which it can accurately reproduce measurements.

Reference 20 provides more details about the variables that impact the performance of conventional instrument transformers.[20]

It is lastly noted that protective relays operate based only on their inputs. If a CT, for example, is supplying a distorted waveform due to the effects of harmonic saturation, the relay may respond in a different, and unwanted, way than it does to nearly sinusoidal inputs.[21]

FERC/NERC Regulation

Federal regulations designed to protect the nation’s electric grid from the potentially severe and widespread impact of a geomagnetic disturbance (GMD) are in the process of being adopted. Following several years of study, the Federal Energy Regulatory Commission (FERC) initiated a rulemaking in 2012, the first of its kind, directing NERC to develop and submit for approval Reliability Standards to protect the grid from the impact of GMDs.

In Order No. 779, FERC determined that the risk posed by GMD events, and the absence of Reliability Standards to address GMD events, posed a risk to system reliability that justified its precedent-setting order directive to NERC to develop Reliability Standards to address the issue. In order to expedite the standards-setting process, FERC ordered NERC to develop mandatory standards in two stages, both of which are now underway.

In the first stage, FERC directed NERC to submit Reliability Standards that required owners and operators of the bulk-power system to develop and implement operational procedures to mitigate the effects of GMDs to ensure grid reliability. These operational procedures were considered a “first step” to address the reliability gap and were approved by FERC in June 2014. These standards become mandatory on January 1, 2015.

In the second stage, FERC has directed NERC to provide more comprehensive protection by requiring entities to perform vulnerability assessments and develop appropriate mitigation strategies to protect their facilities against GMD events. These strategies include blocking GICs from entering the grid, instituting specification requirements for new equipment, and isolating equipment that is not cost effective to retrofit. In subsequent orders, FERC has reiterated its expectation that the second stage GMD standard include measures that address the collection, dissemination, and use of GIC data, by NERC, industry, or others, which may be used to develop or improve GMD mitigation methods or to validate GMD models.

Thus, FERC’s forthcoming standard is likely to require or strongly encourage the installation of GIC monitoring equipment as a means of assessing vulnerability and as the data source by which GIC

[20] J. Duplessis and J. Barker, “Intelligent Measurement for Grid Management and Control”, PACWorld Americas Conference, Raleigh, N.C., September 2013

[21] W. Hagman, “Space Weather in Solar Cycle 24: Is the Power Grid at Risk?”, IEEE PES Boston Chapter & IEEE Com Society Boston Chapter Joint Lecture, April 16, 2013

blocking or other protection schemes are to be implemented. The second stage standards including equipment-based GMD mitigation strategies are due to be filed by NERC in January 2015 and are likely to be approved by FERC in mid-2015.

Intensity Modulated Optical Sensing Technology

Intensity modulated optical sensing technology provides the full system visibility, accuracy and stability required to effectively mitigate GIC effects. This cannot be done with the grid's present information infrastructure comprised primarily of ferromagnetic type instrument transformers.

The fundamental solution to accurate information is to find a physical solution that can observe the system without being electrically coupled to the system, or measurand. This concept precludes any of the IT products either currently available or under development. Instead, it requires a completely new approach to measurement.

Starting in the late 90's, the electric power industry began to experiment with optical techniques that used interferometeric wave and phase modulation as the physical underpinnings of an electrically decoupled measurement system. Unfortunately, this equipment has generally failed in field applications due to its extreme sensitivity to temperature and EMI.

To solve this problem, a new approach based on recently declassified military applications has now been adapted to the needs of the electric power grid – thus achieving the objective of a highly accurate and reliable measurement device that is not electrically coupled to the measurand.

How the technology works:

The U.S. Naval Research Lab (NRL) has been a leader in optical sensing research for over 50 years. Similar to the power industry's experience with interferometric sensors[22], the Navy found that the acute temperature and EMI sensitivity of these devices caused them to fail in mission critical, field applications. To solve these problems, the NRL ultimately developed a highly stable, *intensity* modulated optical sensor that has no temperature sensitivity, no susceptibility to EMI, no frequency modulation, and has been proven to operate accurately in very harsh conditions for long periods of time. This technology, vetted over decades, has now been adapted to measure voltage, current, phase and other characteristics of electric phenomena, and can deliver accurate, stable and reliable performance in rigorous field applications on the power system.

An intensity modulated optical monitoring system consists of a transducer that is located within the force field it is measuring, a light source located some distance away, a fiber optic transmitting cable, at least one fiber collector or return cable, and power electronics.

A sensing element is held securely within the transducer; this is a material that is deliberately selected based upon the measuring application and which responds to changes in the force to which it is subjected. This force is characterized by a magnitude and frequency. In the case of acoustic measurements, and as shown in Figure 6, this material is a diaphragm. Physical displacement of the sensor is being directly measured but this movement is ultimately a function of the force (i.e., the measurand) acting upon it.

Light of a known intensity (P_T) from a light-emitting diode (LED) is coupled into an optical fiber for transmission to the sensing element where it is modulated in accordance with the state of the measurand.

[22] As gauged by general polled feedback

Reflected light of a varying intensity (P_R) is collected by at least one return fiber for transmission back to a photo-detector.

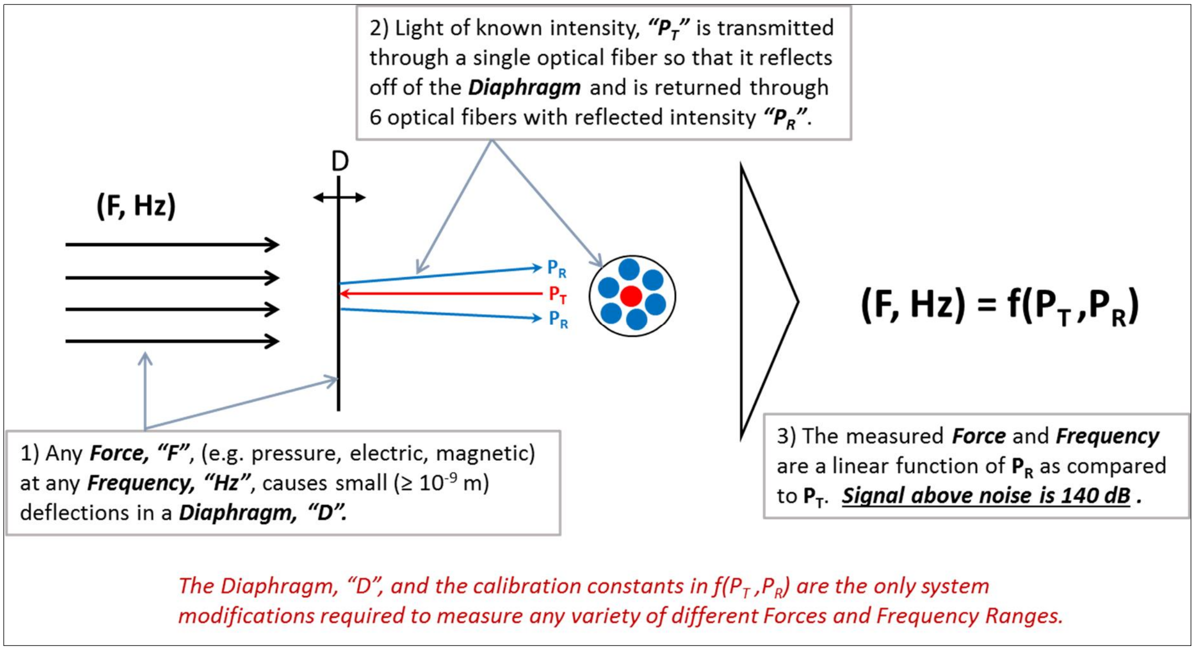

Figure 6

Intensity Modulated Optical Sensing – Fundamental Concept

The intensity of the light returned through the fiber correlates to the force exerted on the sensing element and the frequency with which it is changing. As an example, consider an acoustical measurement. As sound changes, the diaphragm moves and the resultant distance between the fiber probe and the diaphragm changes. Note that the fiber probe is stationary; it is the movement of the sensing element that alters the distance between the probe and the sensor. If that distance becomes smaller by way of displacement of the diaphragm towards the fiber probe, the reflectance changes and the intensity of the reflected light captured by the return fibers decreases (Figure 7). As the distance increases, more reflected light is captured by the return fibers and, consequently, P_R increases (Figure 8).

One transmit fiber and only one return fiber is depicted in Figures 7 and 8. The use of multiple return fibers amplifies the sensitivity of this intensity modulated technology, resulting in the ability to detect displacement changes of the sensing element on the order of 10^{-9} meters.

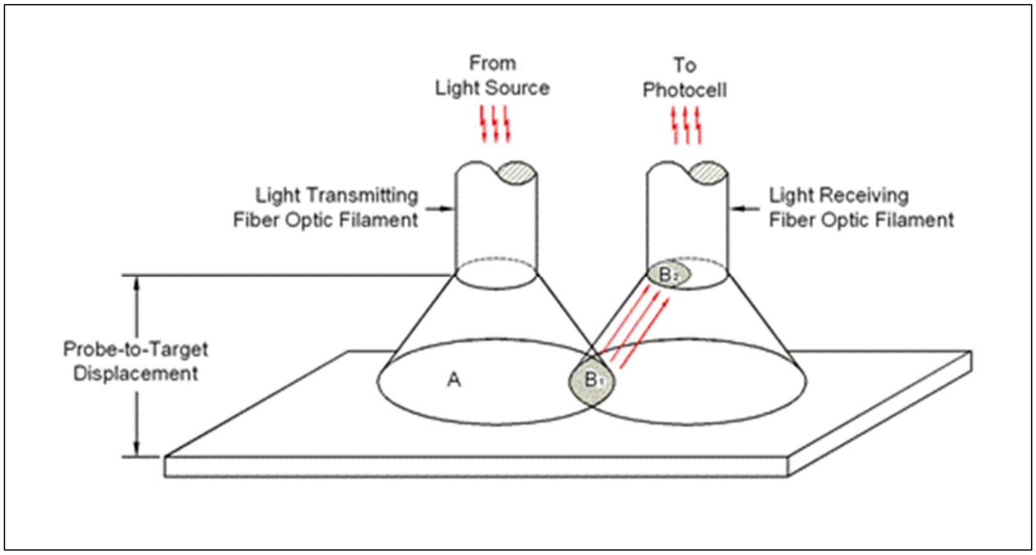

FIGURE 7[23]
P_R Decreases as Displacement between Probe and Diaphragm Decreases

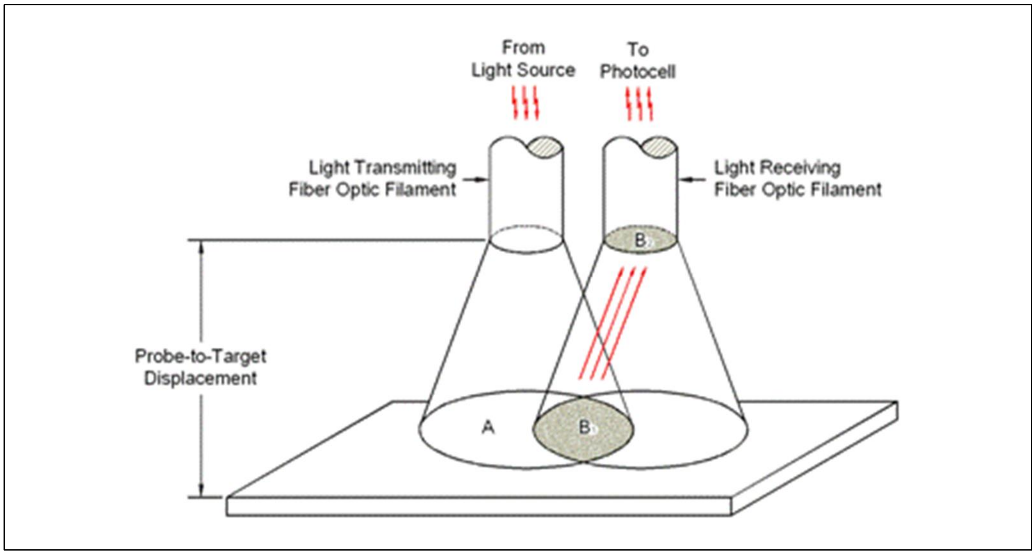

FIGURE 8[24]
P_R Increases as Displacement between Probe and Membrane Increases

Adaptation

Adapting Intensity Modulated Optical Sensors to Measure Electrical Phenomena:

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[23] Yury Pyekh, "Dynamic Terrain Following: NVCPD Scanning Technique Improvement", Fig. 3.7, Thesis Presented to the Academic Faculty of Georgia Institute of Technology, August 2010.
[24] Yury Pyekh, "Dynamic Terrain Following: NVCPD Scanning Technique Improvement", Fig. 3.8, Thesis Presented to the Academic Faculty of Georgia Institute of Technology, August 2010.

Laws of physics are used to adapt the intensity modulated (IM) optical sensors to measure current and voltage. For example, principles of Lorentz's Force are applied to build the IM optical (AC) current sensor.

A Lorentz force, given by F = BLI and illustrated in Figure 9, will result when a current (I) carrying conductor passes through a non-varying magnetic field with flux density, B for some length, L.

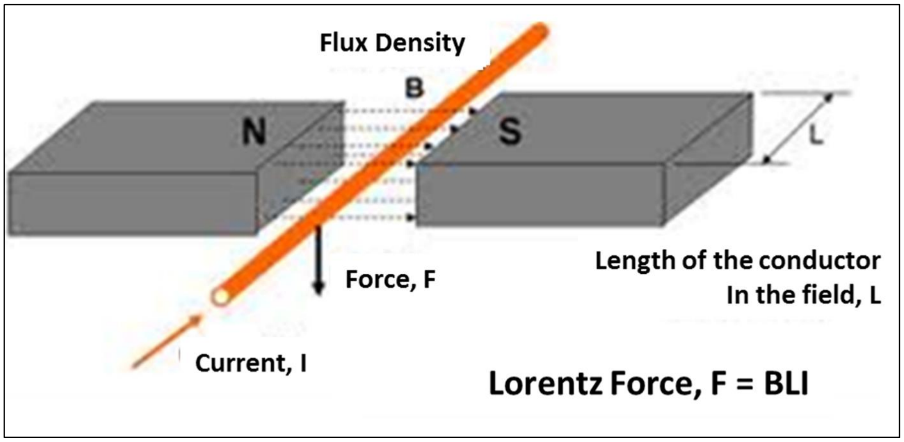

FIGURE 9
Lorentz Law

Accordingly, the current sensing element (Figure 10) connects to the line conductor; as current changes, variations in the Lorentz Force will result in the physical displacement of the sensing element. The intensity of light reflected back will therefore alter proportionally to the changes in the current.

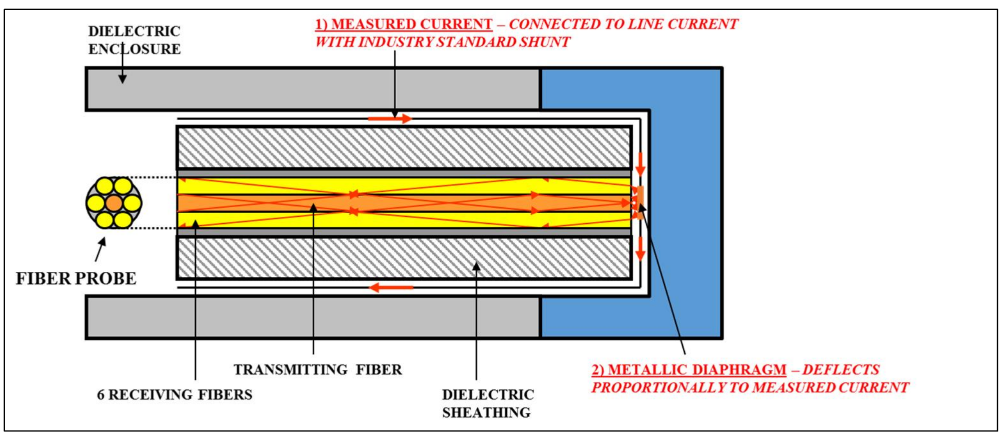

FIGURE 10
Intensity Modulated Fiber Optic Current Sensor

For voltage measurements, the selection of the sensing element is key. Here, a piezoelectric material is selected that has very stable physical characteristics that vary in a known way as the electric field in which the material is placed varies. A reflected surface affixed to the end of the sensing element will physically displace, therefore, as the material deflects relative to changes in the electric field.

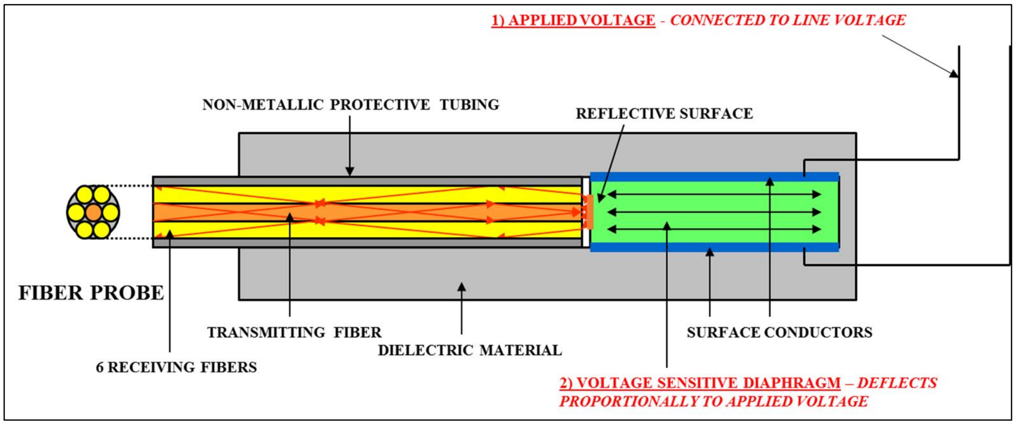

FIGURE 11
Intensity Modulated Fiber Optic Voltage Sensor

The IM optical current and voltage sensors are housed in a common transducer. The physical dimensions of these sensors are very small; the length of a sensor, its maximum dimension, is typically shorter than a few inches. This makes it possible to hold several sensors within one transducer, including IM optical temperature sensors.

IM optical sensing technology is adapted differently to measure DC current and voltage but is not discussed in this paper.

Advantages

Accurate, Repeatable Measurement over an Extremely Wide Range of Values and Frequencies

The fact that Intensity Modulated (IM) optical sensing is passive, non-ferromagnetic and non-interferometry based is central to why this technology delivers a step-change improvement in performance over both conventional instrument transformers and interferometry-based optical equipment.

First, because of its passivity, an IM optical transducer does not disturb the (power) system it observes. The sensing element is non-conductive and the transducer is electrically decoupled from the grid; light is the 'exchange medium' of the transducer and an electrical system is not altered by light. The transducer therefore 'sees' exactly what exists on the power system and this creates notably higher accuracy than what can be achieved by even the most accurate of metering class instrument transformers.

Second, because IM optical sensing is electrically de-coupled and is not ferromagnetic, traditional burdens have no influence on the transducer and the power system cannot negatively impact its measuring capability. IM optical sensors have no saturation curve; their equivalent operating "curve", and therefore performance, is perfectly linear throughout their wide measurement range. By removing variables introduced by system and burden influences, which have plagued the performance of conventional ITs in unpredictable ways for decades, the industry gains automatic assurances that the IM optical transducer is maintaining the accuracy it should at all times. This creates consistent accuracy and therefore, repeatability.

A third advantage of IM optical sensors' non-ferromagnetic based operation is that frequency has no influence on its measuring capabilities. While varying the frequency does alter the shape of a saturation curve that defines the operating characteristics of a conventional IT, it has no effect on the linear operating curve of an IM optical sensor. IM sensors can measure voltage and current at frequencies from quasi-DC to several thousand Hertz. There are no concerns about resonant frequencies associated with inductive and capacitive voltage transformers. This measuring technology therefore affords the power industry the opportunity to view a broad range of non-fundamental frequency components with the same accuracy as measurements at the fundamental frequency (50/60 Hz) and therefore, to perform incredibly insightful power quality studies.

While the pseudo-linear range of a conventional IT's saturation curve is not large, affording only an approximate 20 dB dynamic range, the linear range of operation of an IM optical sensor delivers an approximate >130 dB dynamic range. This means that a single IM optical current sensor, for example, can measure an extremely large fault current, and at once, an exceptionally small harmonic current with identical accuracy. An IM optical system's measuring range is only limited by its noise floor, which is much lower than any other conventional or non-conventional field measurement device that is currently available.

Figure 12 gives a visual representation of the range of (current/voltage) magnitudes over which a conventional IT will yield accurate measurements (the vertical height of the blue shaded area at 60 HZ) and the limiting influence of frequency on a conventional IT's accurate measuring capabilities (as given by the diminishing height of the blue-shaded area as the frequency decreases/increases). In contrast, the much broader, frequency independent, and notably more accurate measuring capabilities of an IM monitoring system are indicated by the encompassing white backdrop that frames the graph in Figure 12.

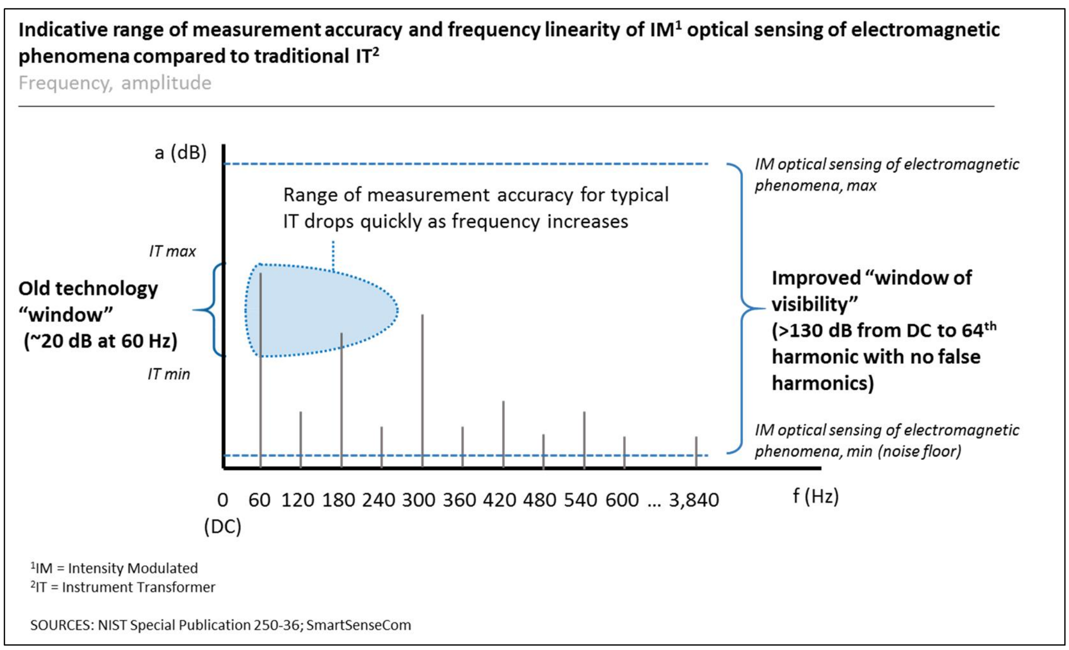

FIGURE 12
Accuracy/ Linearity as a Function of Frequency
(For an IM Optical Monitoring System versus a Conventional IT)

Safety and Risk Reduction

A separate, but equally important, advantage of passive IM optical sensors is safety and risk reduction in the unlikely event of the IM optical system's failure. With a conventional IT, the electrical grid extends all the way to the meter or protective device and the possibility exists for workers to be injured or even killed if they were to inadvertently come into contact with an open-circuited CT secondary. In contrast, the equivalent "secondary" side of an IM optical transducer is fiber optic cable carrying light. It presents no safety hazard. Moreover, should a conventional IT fail, it typically brings the circuit down with it, either due to catastrophic fire or a fault that trips the breaker. In comparison, the IM has no influence on the power system it is observing, and if it should fail, the power system would typically continue to operate as usual.

An additional benefit of being non-ferromagnetic is that periodic field testing to verify operating characteristics and insulation integrity is not necessary for an IM optical transducer. In fact, because an IM optical transducer is electrically decoupled from the grid, there is no requirement for the use of dielectric materials such as oil or SF6 in the device. The combination of these factors reduces O&M costs and expedites safe system restoration after outages.

"IM" Optical Sensing as a Comprehensive Solution to Identifying and Measuring Impacts of GIC

The concerns about GMD are justified and the effects of GIC well documented. The path forward becomes clear after reflection upon just a few of the industry comments about GIC:

- "Accurate estimation of the VAR consumption of the transformer during a GMD event is critical for proper mitigation of effects of GIC on power system stability."
- "Increase in VAR demand is one of the major concerns during a GMD event. The loss of reactive power could lead to system voltage collapse if it is not identified and managed properly."
- "…the magnetizing current pulse injects significant harmonics into the power system which can have a significant impact on shunt capacitor banks, SVCs and relays and could compromise the stability of the grid."

The GIC mitigation solution lies in the ability to quantify its effects in real time. The industry has not been able to do that up to now with the measuring devices available. IM optical monitoring systems change this.

An AC current and voltage IM optical transducer must be installed on the high-voltage side of a susceptible transformer. This will measure the VAR consumption of the transformer as well as any harmonics generated given the operating state of the transformer, well into the kHz range. A DC current IM optical transducer would be installed on the grounded neutral connection of the transformer. IM optical technology provides for accuracies of approximately one percent at low magnitude DC currents, 1 – 25A, allowing exacting correlation between DC currents and concurrently observed effects on the transformer (reactive energy consumption and harmonic profile).

Because of the many variables that contribute to the vulnerability of the transformer and connected power system, even given the same GIC magnitude, the transformer/system response is expected to be different. For this reason, it is not enough to install a simple DC current monitor, such as a Hall Effect sensor, on the neutral ground connection of a transformer. Even if one were to look past the instability of such devices, particularly at low DC current levels (< 25A), a DC measurement alone does not afford reliable predictability about the associated power system impact.

Conclusion

The negative impacts of geomagnetically induced currents (“GIC”) are understood at a high level. GIC flow negatively impacts certain power transformers causing half-cycle saturation that leads to increased demand for reactive power, generation of harmonics, and transformer heating. This in turn negatively impacts electric power transmission systems; at its worse, causing grid instability due to voltage collapse, misoperation of protection equipment (e.g., capacitor banks, overcurrent relays), damage to sensitive loads due to poor power quality, and/or thermal damage to the transformer. However, better system visibility is required to develop effective GIC mitigation strategies. For example, what is the actual change in reactive power and the harmonic generation profile at a specific location when GIC is present? How will the surrounding transmission system actually respond to these changes?

It is important to have accurate measurements of system state during abnormal operating conditions. Unfortunately, traditional ferromagnetic-type instrument transformers are at risk of being affected by GIC conditions too. There is no way of validating, in real time and while energized, whether an instrument transformer is saturated or not, so it is possible that information provided to protective devices may be riddled with error on the magnitude of over 12 percent. Moreover, classical instrument transformers do not have the ability to reproduce harmonics with any guaranteed accuracy (even when demagnetized) much beyond the 3rd harmonic.

The GMD/GIC phenomena is a prime example where the industry’s inability to sufficiently measure will leave it struggling to manage unless we embrace change. A solution to gain full (and stable!) system visibility was introduced. It is an optical solution called Intensity Modulated (IM) optical measuring; it resolves the grid’s present-day measuring inadequacies and is different than earlier optical techniques which, while promising, have proven to be unstable under field conditions due to extreme temperature instability and electromagnetic interference. An IM optical system was described along with some example adaptations for its use in measuring electrical phenomena. Advantages of IM optical transducers, rooted in their passivity and non-ferromagnetic characteristics, were enumerated. These include a step-change improvement in accuracy; hardening to otherwise influencing ‘environmental’ variables resulting in stability and consistency in measurements, and therefore, repeatability; the ability to observe the power system more comprehensively than ever before through one transducer; and significant enhancement in personnel and system safety.

The GIC mitigation solution lies in the ability to quantify its effects in real time. This can be accomplished through intensity modulated optical monitoring systems.

Group Comments on NERC Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

November 21, 2014

Draft standard TPL-007-1, "Transmission System Planned Performance for Geomagnetic Disturbance Events," is not a science-based standard. Instead, the apparent purpose of standard TPL-007-1 is to achieve a preferred policy outcome of the North American Electric Reliability Corporation (NERC) and its electric utility members: avoidance of installation of hardware-based protection against solar storms. The draft standard achieves this apparent purpose through a series of scientific contrivances that are largely unsupported by real-world data. Potential casualties in the millions and economic losses in trillions of dollars from severe solar storms instead demand the most prudent science-based standard.

A 2010 series of comprehensive technical reports, "Electromagnetic Pulse: Effects on the U.S. Power Grid"[1] produced by Oak Ridge National Laboratory for the Federal Energy Regulatory Commission in joint sponsorship with the Department of Energy and the Department of Homeland Security found that a major geomagnetic storm "could interrupt power to as many as 130 million people in the United States alone, requiring several years to recover."

A 2013 report produced by insurance company Lloyd's and Atmospheric and Environmental Research, "Solar Storm Risk to the North American Electric Grid,"[2] found that:

> "A Carrington-level, extreme geomagnetic storm is almost inevitable in the future. While the probability of an extreme storm occurring is relatively low at any given time, it is almost inevitable that one will occur eventually. Historical auroral records suggest a return period of 50 years for Quebec-level storms and 150 years for very extreme storms, such as the Carrington Event that occurred 154 years ago."
>
> "The total U.S. population at risk of extended power outage from a Carrington-level storm is between 20-40 million, with durations of 16 days to 1-2 years. The duration of outages will depend largely on the availability of spare replacement transformers. If new transformers need to be ordered, the lead-time is likely to be a minimum of five months. The total economic cost for such a scenario is estimated at $0.6-2.6 trillion USD."

A 2014 paper published in the Space Weather Journal, "Assessing the impact of space weather on the electric power grid based on insurance claims for industrial electrical equipment"[3] by C. J. Schrijver, R. Dobbins, W. Murtagh, and S.M. Petrinec found:

> "We find that claims rates are elevated on days with elevated geomagnetic activity by approximately 20% for the top 5%, and by about 10%for the top third of most active days ranked by daily maximum variability of the geomagnetic field."
>
> "The overall fraction of all insurance claims statistically associated with the effects of geomagnetic activity is 4%."

"We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude."

Given the extreme societal impact of a major solar storm and large projected economic losses, it is vital that any study by NERC in support of standard TPL-007 be of the highest scientific caliber and rigorously supported by real-world data. The unsigned white papers of the NERC Standard Drafting Team fail scientific scrutiny for the following reasons:

1. The NERC Standard Drafting Team contrived a "Benchmark Geomagnetic Disturbance (GMD) Event"[4] that relies on data from Northern Europe during a short time period with no major solar storms instead of using observed magnetometer and Geomagnetically Induced Current (GIC) data from the United States and Canada over a longer time period with larger storms. This inapplicable and incomplete data is used to extrapolate the magnitude of the largest solar storm that might be expected in 100 years—the so-called "benchmark event." The magnitude of the "benchmark event" was calculated using a scientifically unproven "hotspot" conjecture that averaged the expected storm magnitude downward by an apparent factor of 2-3. This downward averaging used data collected from a square area only 500 kilometers in width, despite expected impact of a severe solar storm over most of Canada and the United States.
2. The NERC Standard Drafting Team contrived a table of "Geomagnetic Field Scaling Factors" that adjust the "benchmark event" downward by significant mathematical factors dependent on geomagnetic latitude. For example, the downward adjustment is 0.5 for Toronto at 54 degrees geomagnetic latitude, 0.3 for New York City at 51 degrees geomagnetic latitude, and 0.2 for Dallas at 43 degrees geomagnetic latitude. These adjustment factors are presented in the whitepaper in a manner that does not allow independent examination and validation.
3. The NERC Standard Drafting Team first contrived a limit of 15 amps of GIC for exemption of high voltage transformers from thermal impact assessment based on limited testing of a few transformers. When the draft standard failed to pass the second ballot, the NERC Standard Drafting Team contrived a new limit of 75 amps of GIC for exemption of transformers from thermal impact assessment, again based on limited testing of a few transformers. The most recent version of the "Screening Criterion for Transformer Thermal Impact Assessment"[5] whitepaper uses measurements from limited tests of only three transformers to develop a model that purports to show all transformers could be exempt from the thermal impact assessment requirement. It is scientifically fallacious to extrapolate limited test results of idiosyncratic transformer designs to an installed base of transformers containing hundreds of diverse designs.

The above described contrivances of the NERC Standard Drafting Team are unlikely to withstand comparison to real-world data from the United States and Canada. Some public GIC data exists for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper “Benchmark Geomagnetic Disturbance Event Description.” Some public disclosures of transformer failures during and shortly after solar storms exist for the United States and Canada, but the NERC Standard Drafting Team did not reference this data in their unsigned whitepaper “Screening Criterion for Transformer Thermal Impact Assessment.”

NERC is in possession of two transformer failure databases.[6] [7] This data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Screening Criterion for Transformer Thermal Impact Assessment. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on transformer failures, contrary to Section 6.0 of the NERC Standards Processes Manual, “Processes for Conducting Field Tests and Collecting and Analyzing Data.”[8]

U.S. and Canadian electric utilities are in possession of GIC data from over 100 monitoring locations, including several decades of data from the EPRI SUNBURST system.[9] This GIC data should be released for scientific study and used by the NERC Standard Drafting Team to develop a data-validated Benchmark Geomagnetic Disturbance Event. The NERC Standard Drafting Team failed to conduct appropriate field tests and collect relevant data on measured GIC, contrary to Section 6.0 of the NERC Standards Processes Manual, “Processes for Conducting Field Tests and Collecting and Analyzing Data.”[10]

The NERC whitepaper “Benchmark Geomagnetic Disturbance Event Description” contains “Appendix II – Scaling the Benchmark GMD Event,” a system of formulas and tables to adjust the Benchmark GMD Event to local conditions for network impact modeling. Multiple comments have been submitted to the Standard Drafting Team showing that the NERC formulas and tables are inconsistent with real-world observations during solar storms within the United States.[11] [12] [13] While the NERC Standard Processes Manual requires that the Standard Drafting Team “shall make an effort to resolve each objection that is related to the topic under review,” the Team has failed to explain why its methodology is inconsistent with measured real-world data.[14]

Even the most rudimentary comparison of measured GIC data to the NERC “Geomagnetic Field Scaling Factors” shows the methodology of “Appendix II—Scaling the Benchmark GMD Event” of whitepaper “Benchmark Geomagnetic Disturbance Event Description” is flawed. For example, this comment submitted in standard-setting by Manitoba Hydro:

> “GMD Event of Sept 11-13, 2014 - EPRI SUNBURST GIC data over this period suggests that the physics of a GMD are still unknown, in particular the proposed geoelectric field cut-off is most likely invalid. Based on the SUNBURST data for this period in time one transformer neutral current at Grand Rapids Manitoba (above 60 degrees geomagnetic latitude) the northern most SUNBURST site just on the southern edge of the auroral zone only reached a peak GIC of 5.3 Amps where as two sites below 45 degrees geomagnetic latitude (southern USA) reached peak GIC’s of 24.5 Amps and 20.2 Amps. “[15]

In the above instance, if the NERC "Geomagnetic Field Scaling Factors" were correct and all other factors were equal, the measured GIC amplitude at 45 degrees geomagnetic latitude should have been 1 Amp (5.3 Amps times scaling factor of 0.2). Were other GIC data to be made publicly available, it is exceedingly likely that the "Geomagnetic Field Scaling Factors" would be invalidated, except as statistical averages that do not account for extreme events. Notably, the above observation of Manitoba Hydro is consistent with the published finding of C. J. Schrijver, et. al. that "We find no significant dependence of the claims frequencies statistically associated with geomagnetic activity on geomagnetic latitude."

The EPRI SUNBURST database of GIC data referenced in the above Manitoba Hydro comment should be made available for independent scientific study and should be used by the NERC Standard Drafting Team to correct its methodologies.

American National Standards Institute (ANSI)-compliant standards[16] are required by the NERC Standard Processes Manual. Because the sustainability of the Bulk Power System is essential to protect and promptly restore operation of all other critical infrastructures, it is essential that NERC utilize all relevant safety and reliability-related data supporting assessments of geomagnetic disturbance impacts on "critical equipment" and benefits of hardware protective equipment. Other ANSI standards depend upon and appropriately utilize safety-related data on relationships between structural design or protective equipment and the effective mitigation of earthquakes, hurricanes, maritime accidents, airplane crashes, train derailments, and car crashes.

Given the large loss of life and significant economic losses that could occur in the aftermath of a severe solar storm, and the scientific uncertainly around the magnitude of a 1-in-100 solar storm, the NERC Standard Drafting Team should have incorporated substantial safety factors in the standard requirements. However, the apparent safety factor for the "Benchmark GMD Event" appears to be only 1.4 (8 V/km geoelectric field used for assessments vs. 5.77 V/km estimated).

The NERC Standard Processes Manual requires that the NERC Reliability Standards Staff shall coordinate a "quality review" of the proposed standard.[17] Any competent quality review would have detected inconsistencies between the methodologies of the "Benchmark Geomagnetic Disturbance Event Description" and real world data submitted in comments to the Standard Drafting Team. Moreover, any competent quality review would have required that the Standard Drafting Team use real-world data from the United States and Canada, rather than Northern Europe, in developing the methodologies of the "Benchmark Geomagnetic Disturbance Event Description" and "Screening Criterion for Transformer Thermal Impact Assessment."

Draft standard TPL-007-1 does not currently require GIC monitoring of all high voltage transformers nor recording of failures during and after solar storms.[18] These requirements should be added given the still-developing scientific understanding of geomagnetic disturbance phenomena and its impact on high voltage transformers and other critical equipment.

Going forward, data on observed GIC and transformer failures during solar storms should be publicly released for continuing scientific study. NERC can and should substitute a science-based standard to model the benefits and impacts on grid reliability of protective hardware to prevent long-term blackouts due to solar geomagnetic storms.

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Endnotes:

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[2] "Solar Storm Risk to the North American Electric Grid," Lloyd's and Atmospheric and Environmental Research (2013) available at https://www.lloyds.com/~/media/lloyds/reports/emerging%20risk%20reports/solar%20storm%20risk%20to%20the%20north%20american%20electric%20grid.pdf.
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[8] "Standard Processes Manual, Version 3," NERC (June 26, 2013), page 28, available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.
[9] "SUPPLEMENTAL INFORMATION SUPPORTING REQUEST FOR REHEARING OF FERC ORDER NO. 797, RELIABILITY STANDARD FOR GEOMAGNETIC DISTURBANCE OPERATIONS, 147 FERC ¶ 61209, JUNE 19, 2014 AND MOTION FOR REMAND," Foundation for Resilient Societies (August 2014) available at http://www.resilientsocieties.org/images/Resilient_Societies_Additional_Facts081814.pdf.
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[11] Comment of, "Examination of NERC GMD Standards and Validation of Ground Models and Geo-Electric Fields Proposed in this NERC GMD Standard," J. Kappenman and W. Radasky (July 30, 2014) available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/WhitePaper_NERC_Model_Validation_07302014.pdf.
[12] "Comments of John Kappenman & Curtis Birnbach on Draft Standard TPL-007-1," J. Kappenman and C. Birnbach (October 10, 2014), available at http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/GMD_comments_received_10152014_final.pdf.
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Supplemental Comments of the Foundation for Resilient Societies on NERC Standard TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events November 21, 2014

The Foundation for Resilient Societies, Inc. [hereinafter "Resilient Societies"] separately files today, November 21, 2014 Group Comments that assert multiple failures, both procedural and substantive, that result in material noncompliance with ANSI Procedural Due Process, and with NERC's Standard Processes Manual Version 3, effective on June 26, 2013.

In this separate Supplemental Comment, Resilient Societies incorporates as its concerns the material in comments on NERC Standard TPL-007-1 submitted by John Kappenman and William Radasky (July 30, 2014); John Kappenman and Curtis Birnbach (October 10, 2014); John Kappenman (2 comments dated November 21, 2014); and EMPrimus (November 21, 2014).

We reserve the right to utilize all other comments filed in the development of this standard in a Stage 1 Appeal under NERC's Standard Processes Manual Version 3. In particular but not in limitation, we assert that NERC fails to collect and make available to all GMD Task Force participants and to utilize essential relevant data, thereby causing an unscientific, systemically biased benchmark model that will discourage cost-effective hardware protection of the Bulk Power System; that NERC fails to fulfill the obligations under ANSI standards and under the Standard Processes Manual to address and where possible to resolve on their merits criticisms of the NERC Benchmark GMD Event model. Moreover, if the NERC Director of Standards and Standards Department fail to exercise the "quality control" demanded by the Standard Processes Manual, this will also become an appealable error if the standard submitted on October 27 and released on October 29, 2014 becomes the final standard for the NERC ballot body.

Moreover, an essential element of quality control for NERC standard development and standard promulgation is that the Standard comply with the lawful Order or Orders of the Federal Energy Regulatory Commission. To date, no element of the standard performs the cost-benefit mandate of FERC Order. No. 779.

Resilient Societies hereby refers the Standards Drafting Team and the NERC Standards Department to the filing today, November 21, 2014 of Item 31 in Maine Public Utilities Commission Docket 2013-00415. This filing is publicly downloadable. Appendix A to this filing of as Draft Report to the Maine PUC on geomagnetic disturbance and EMP mitigation includes an assessment of avoided costs, hence financial benefits of installing neutral ground blocking devices, including a range of several devices (Central Maine Power) to as many as 18 neutral ground blocking, and GIC monitors (EMPrimus Report, November 12, 2014, Appendix A in the Maine PUC filing of November 21, 2014). Cost-benefit analysis could and should be applied on a regional basis, in the NERC model and with criteria for application by NERC registered entities. NERC has failed to fulfill its mandate, with the foreseeable effect of suppressing public awareness of the benefits resulting from blockage of GICs to entry through high voltage transmission lines into the Bulk Power System. Another foreseeable result is economic harm to those companies that have invested capital in the development of GMD hardware protection devices and GIC monitors. We incorporate by reference the materials in Maine PUC Docket 2013-00415, Items 30 and 31, filed and publicly retrievable online in November 2014.

Finally, we express concern that the combination of NERC Standards in Phase 1 and in Phase 2, providing no mandatory GIC monitor installations and data sharing with Regional Coordinators, and with state and federal operations centers, effectively precludes time-urgent mitigation during severe solar storms despite timely reports to the White House Situation Room.

NERC has effectively created insuperable barriers to fulfill the purposes of FERC Order No. 779. Without significant improvements that encourage situational awareness by Generator Operators and near-real-time data to mitigate the impacts of solar geomagnetic storms, the only extra high voltage transformers that can be reliably protected will be those with installed hardware protection. Yet this defective standard will provide false reassurance that no hardware protection is required. Also, the scientifically defective NERC model may also preclude regional cost recoveries for protective equipment, by falsely claiming that no protective equipment is required under the assessment methodologies in the standard.

Hence irreparable harm to the reliability of the Bulk Power System, and to the residents of North America, is a foreseeable result of the process and substantive result of this standard.

Respectfully submitted by:

Submitted by:

Thomas S. Popik
Chairman
Foundation for Resilient Societies

William R. Harris
International Lawyer
Secretary, Foundation for Resilient Societies

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.
4. The second draft of the proposed Reliability Standard was posted for formal comment and additional ballot from August 27, 2014 through October 10, 2014.
5. The third draft of the proposed Reliability Standard was posted for formal comment and additional ballot from October 28, 2014 through November 21, 2014.

Description of Current Draft

This is the fourth draft of the proposed Reliability Standard. It is posted for final ballot.

Anticipated Actions	Anticipated Date
Final ballot	December 2014
Presentation to NERC Board of Trustees for adoption	December 2014

Effective Dates

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale:

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s), in accordance with Requirement R1.

Rationale for Requirement R1:

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s*). [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1,

which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Rationale for Requirement R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

R4. Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1. If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the

requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Rationale for Requirement R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Rationale for Requirement R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:

A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the Benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Table 1 – Steady State Planning Events				
Steady State: a. Voltage collapse, Cascading and uncontrolled islanding shall not occur. b. Generation loss is acceptable as a consequence of the planning event. c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.				
Category	**Initial Condition**	**Event**	**Interruption of Firm Transmission Service Allowed**	**Load Loss Allowed**
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes
1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. 2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event). 3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{1}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \tag{2}$$

where L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2– Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[2] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2) or Table 2, β is applied to the reference geoelectric field using equation (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[3] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \tag{3}$$

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

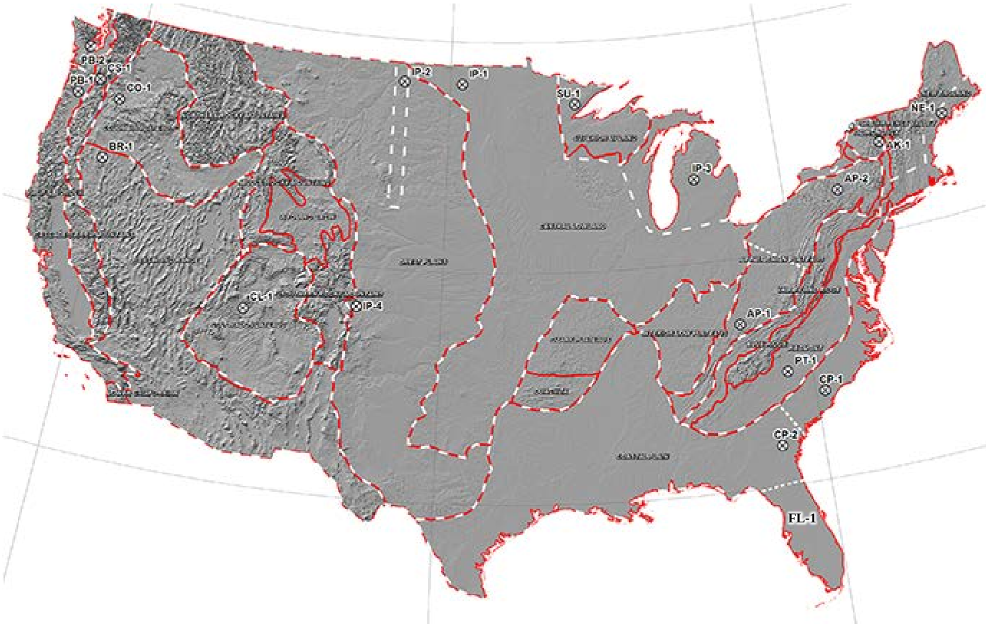

Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

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[4] Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 – Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Rationale: Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74.

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

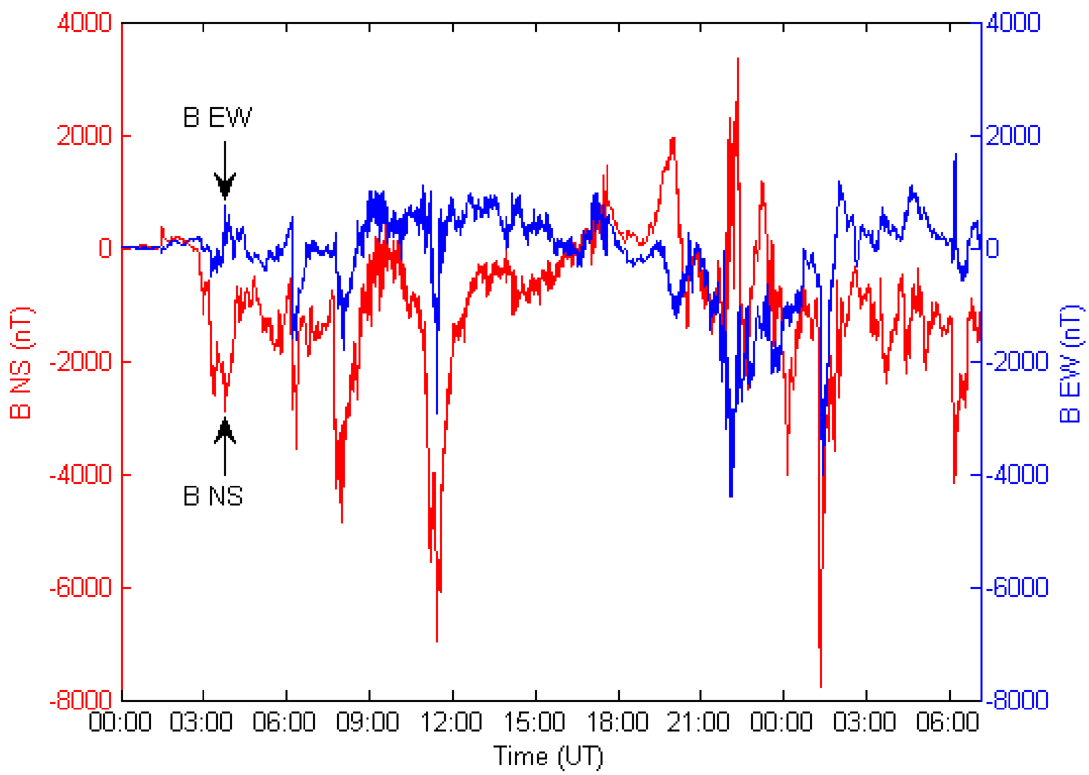

Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

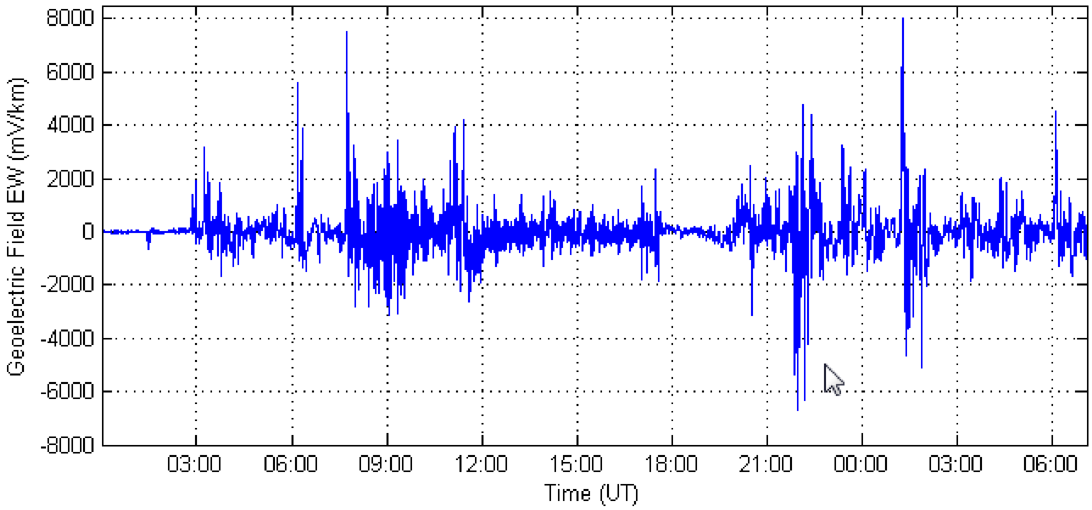


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

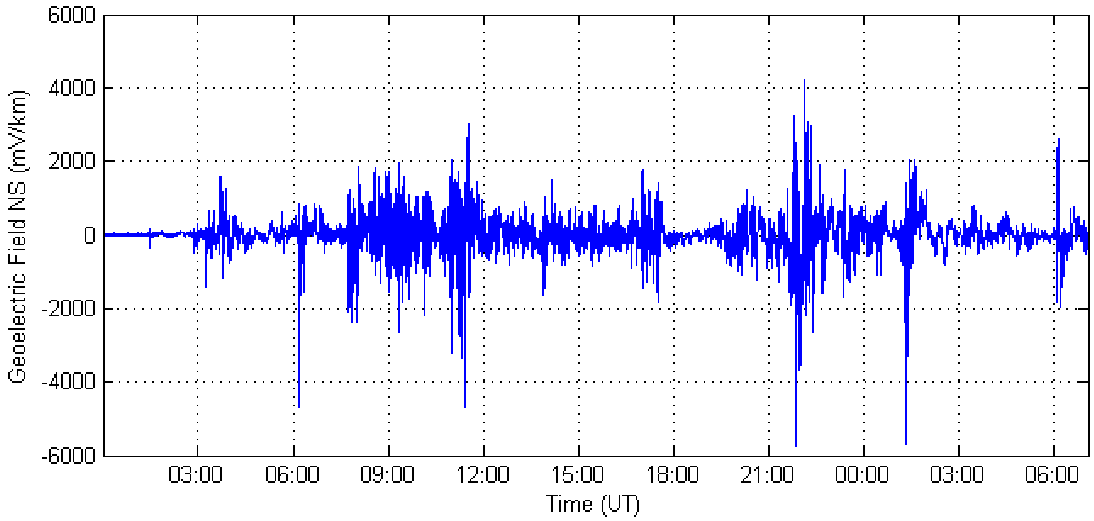


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

For Requirements R1, R2, R3, R5, and R6, each responsible entity shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

R5	Long-term Planning	Medium	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly

			power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

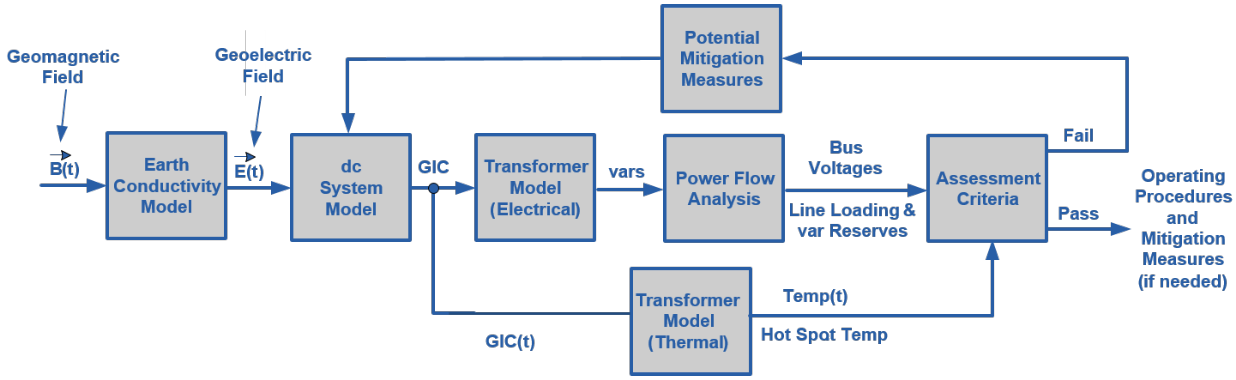
Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.
3. The first draft of the proposed Reliability Standard was posted for formal comment and initial ballot from June 13, 2014 through July 30, 2014.
4. The second draft of the proposed Reliability Standard was posted for formal comment and additional ballot from August 27, 2014 through October 10, 2014.
5. The third draft of the proposed Reliability Standard was posted for formal comment and additional ballot from October 28, 2014 through November 21, 2014.

Description of Current Draft

This is the ~~third~~fourth draft of the proposed Reliability Standard. It is posted for ~~25-day comment and additional~~final ballot.

Anticipated Actions	Anticipated Date
~~25-day Formal Comment Period with Additional Ballot~~	~~November 2014~~
Final ballot	December 2014
~~BOT~~Presentation to NERC Board of Trustees for adoption	December 2014

Effective Dates

See *Implementation Plan for TPL-007-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Rationale:

Instrumentation transformers and station service transformers do not have significant impact on ~~GIC~~geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s), in accordance with Requirement R1.

Rationale for Requirement R1:

In some areas, planning entities may determine that the most effective approach to conduct~~ing~~ a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s*). [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

Rationale for Requirement R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1,

which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Rationale for Requirement R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

R4. Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.

4.3. The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.

4.3.1. If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the

requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

Rationale for Requirement R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

Rationale for Requirement R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 ~~is~~can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, ~~p~~Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R6. Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. 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, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, 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. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.

7.3. Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Rationale for Requirement R7:

Corrective Action Plans are defined in the NERC Glossary of Terms:

A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the Benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Table 1 – Steady State Planning Events

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the planning event.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
GMD GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event).
3. 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. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 2~~:~~ Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[2] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2) or Table 2, β is applied to the reference geoelectric field using equation (1) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[3] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \qquad (3)$$

where *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

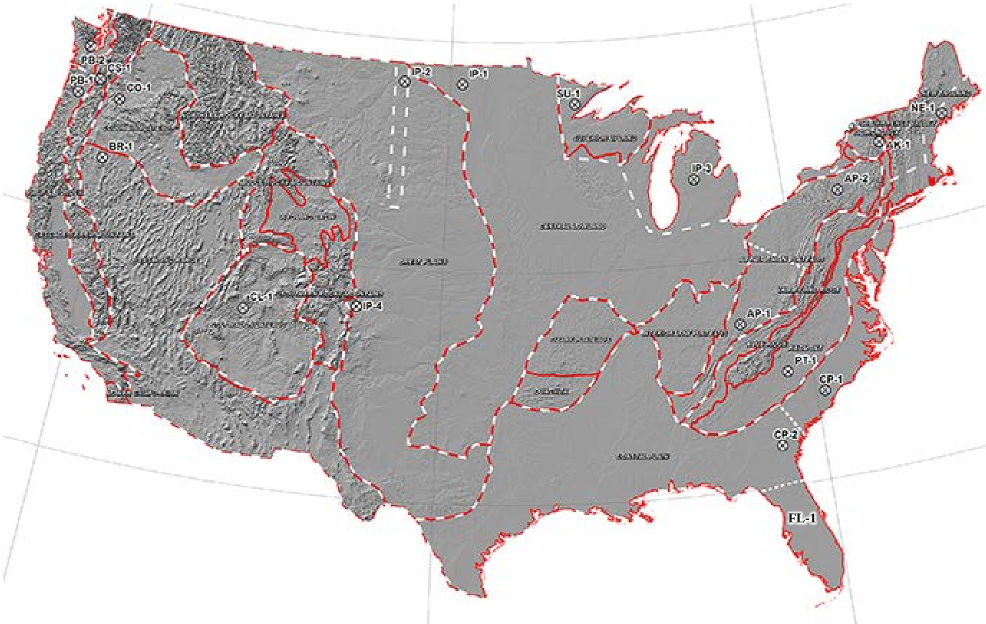


Figure 1: Physiographic Regions of the Continental United States[4]

Figure 2: Physiographic Regions of Canada

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4 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 ~~–~~ – Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Rationale: Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74.

Table 4~~:~~ – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]

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 geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β.

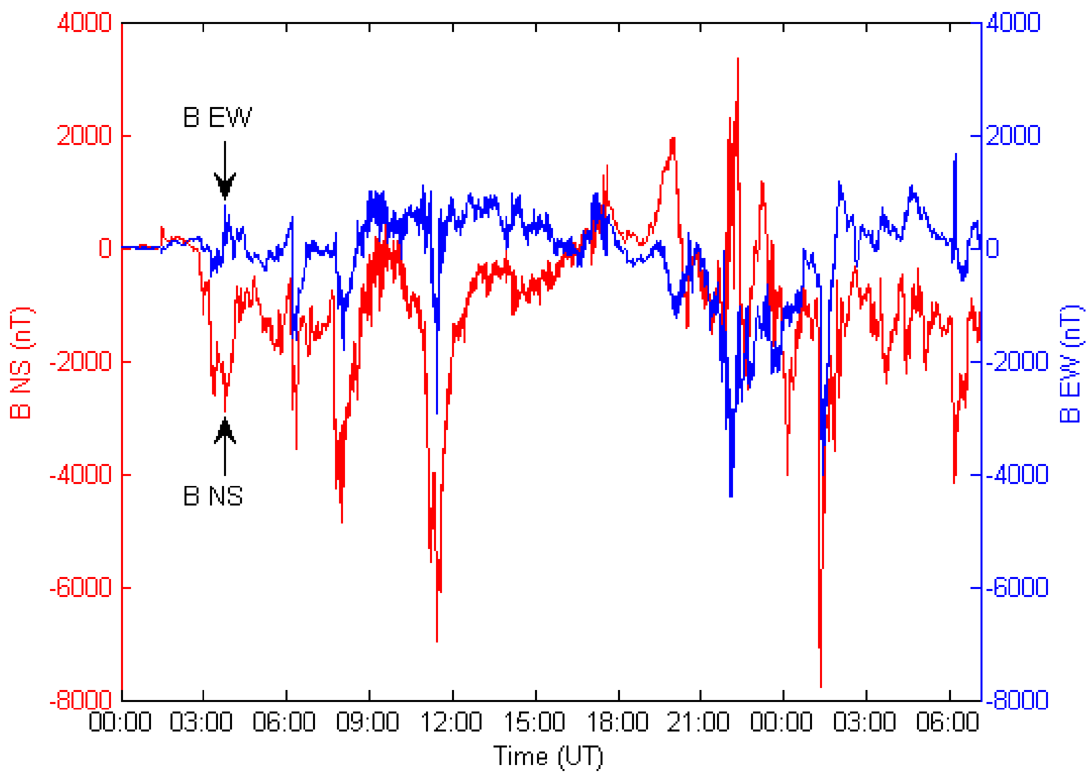

Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

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[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

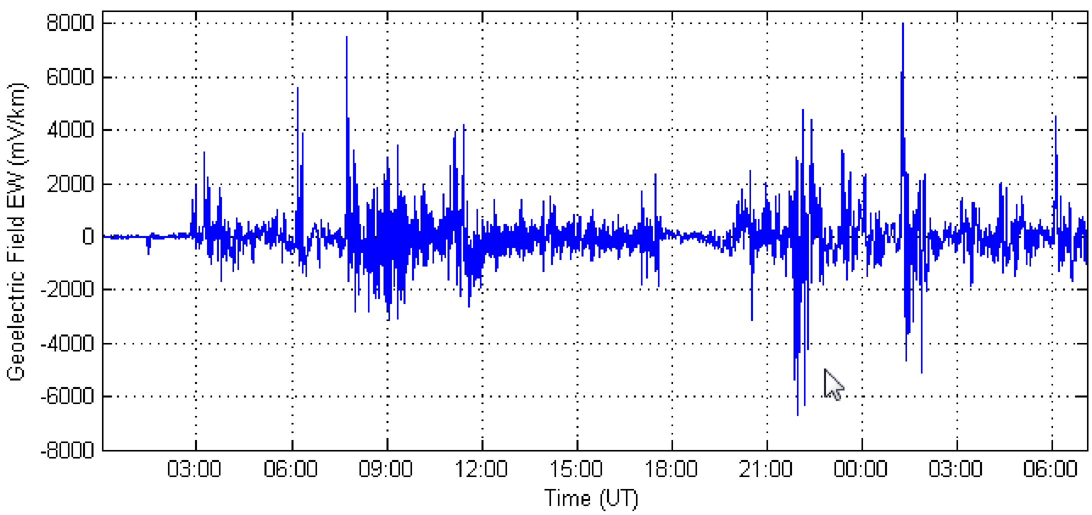


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

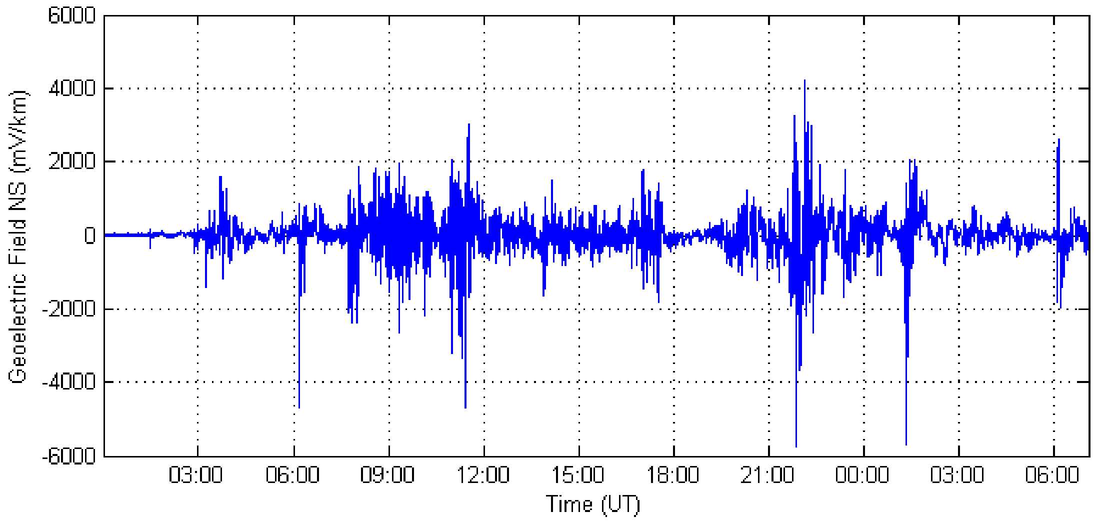


Figure 5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

For Requirements R1, R2, R3, R5, and R6, each responsible entity shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes~~:~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).

R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

R5	Long-term Planning	Medium	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	Long-term Planning	Medium	The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly

			power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7	Long-term Planning	High	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

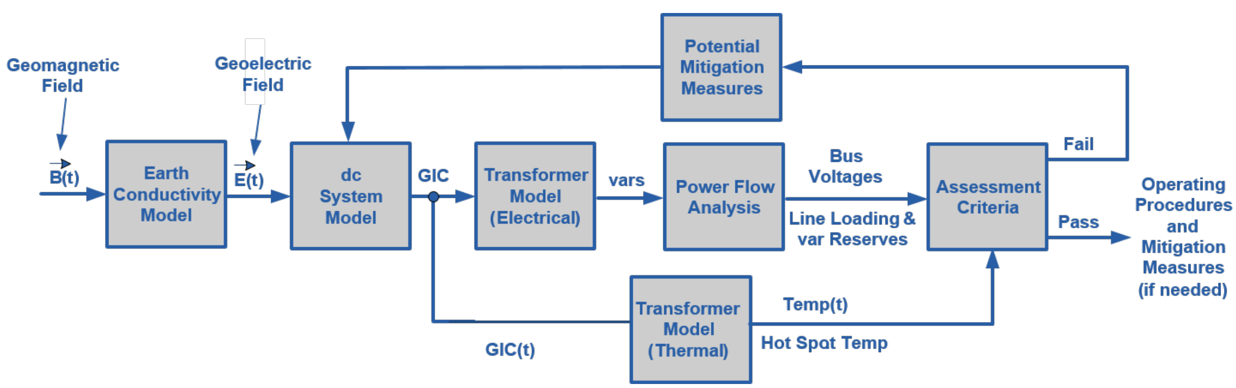
Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required,

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Approvals Required

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-1 is approved by the applicable governmental authority:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

Planning Coordinator with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Planner with a planning area that includes an applicable power transformer(s) as listed in *section 4.2 Facilities* of the standard;

Transmission Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard; and

Generator Owner who owns a power transformer(s) as listed in *section 4.2 Facilities* of the standard.

Applicable Facilities

Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Conforming Changes to Other Standards

None

Effective Dates

Compliance with TPL-007-1 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-1 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R2 shall become effective on the first day of the first calendar quarter that is 18 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required,

Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3, Requirement R4, and **Requirement R7** shall become effective on the first day of the first calendar quarter that is 60 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3, Requirement R4, and Requirement R7 shall become effective on the first day of the first calendar quarter that is 60 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
December 5, 2014

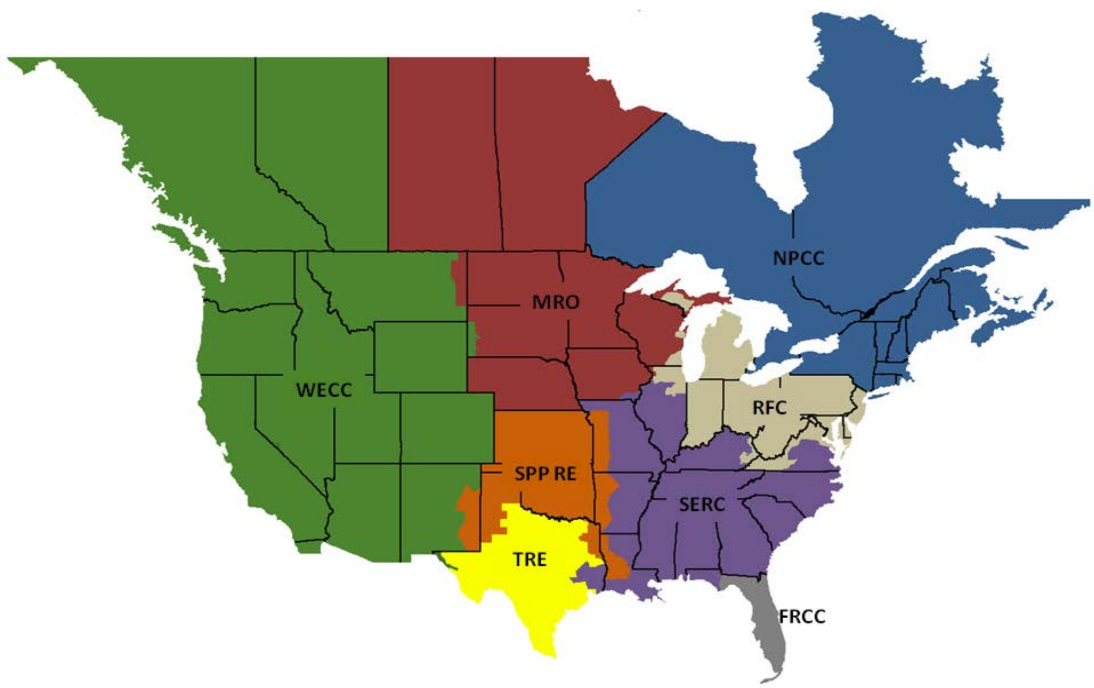
RELIABILITY | ACCOUNTABILITY

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)

Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the “Halloween event” of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

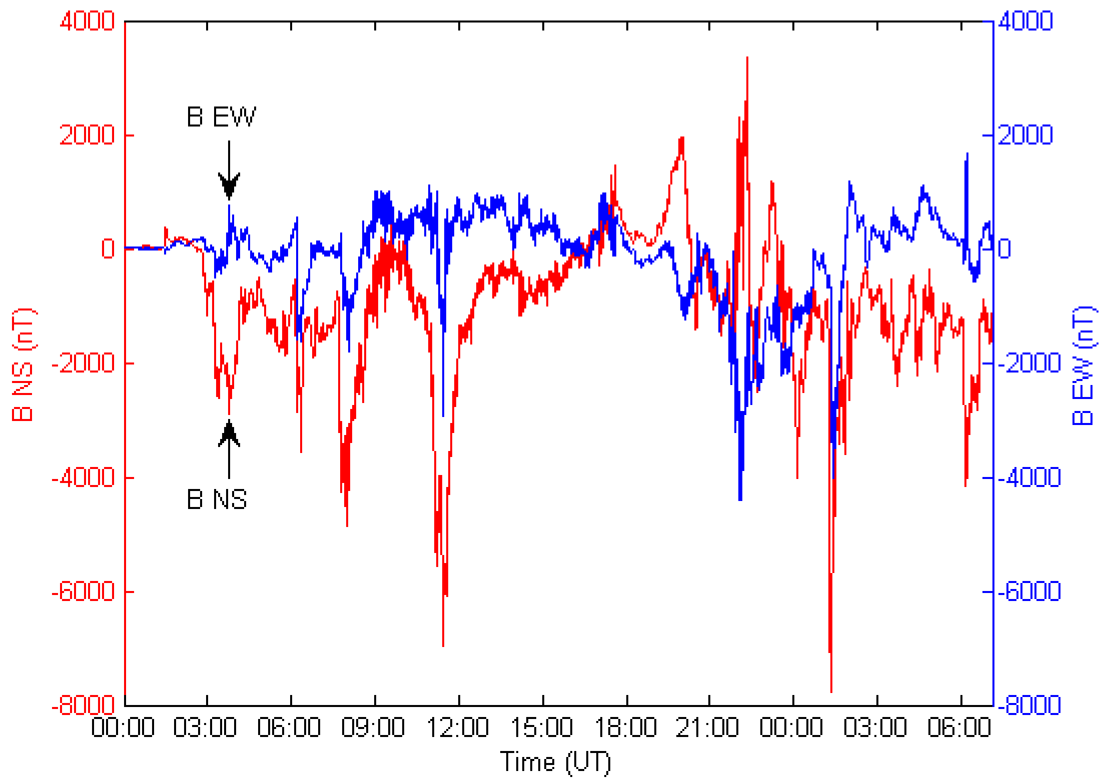


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

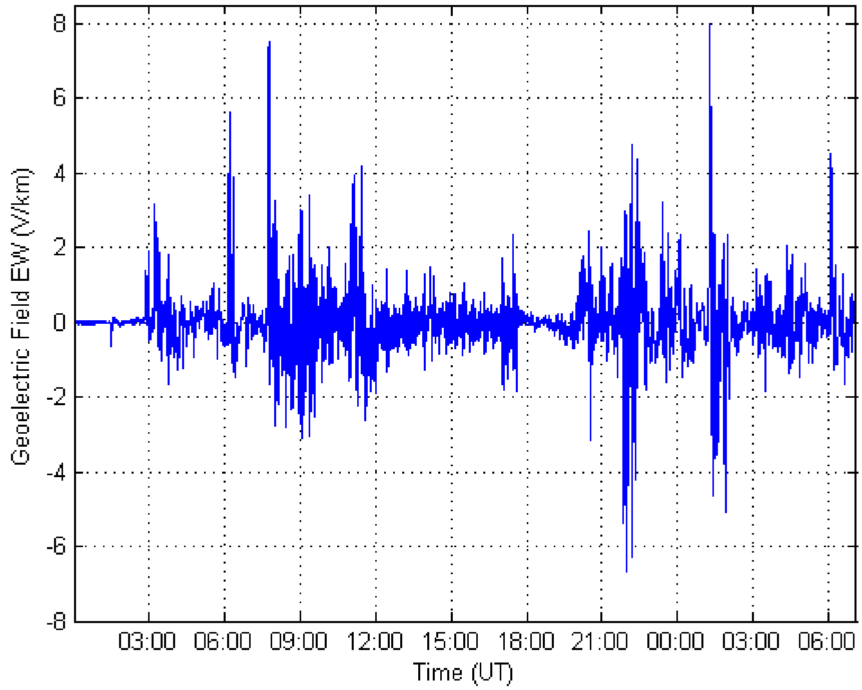


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

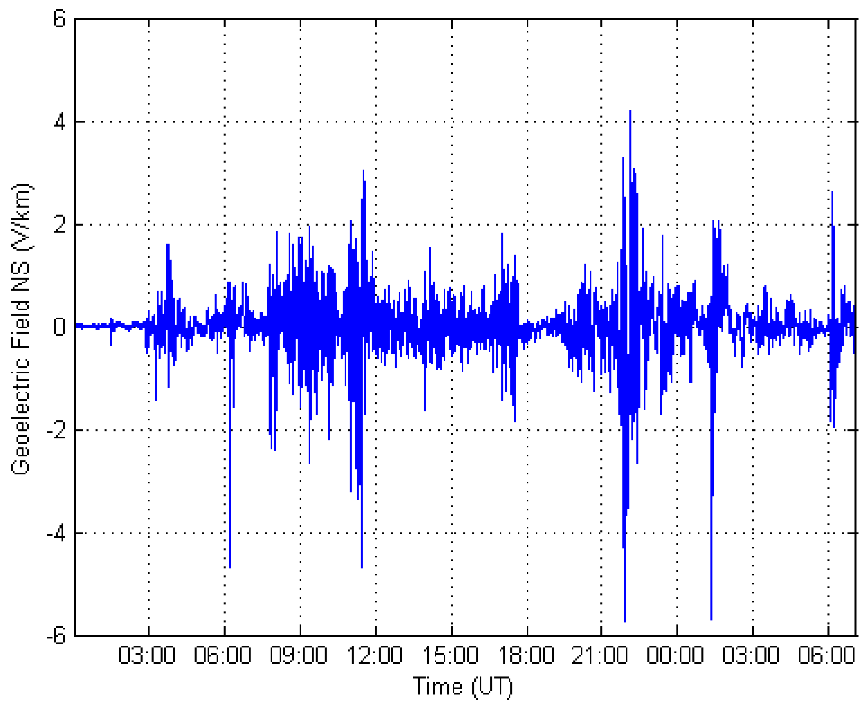


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

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[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

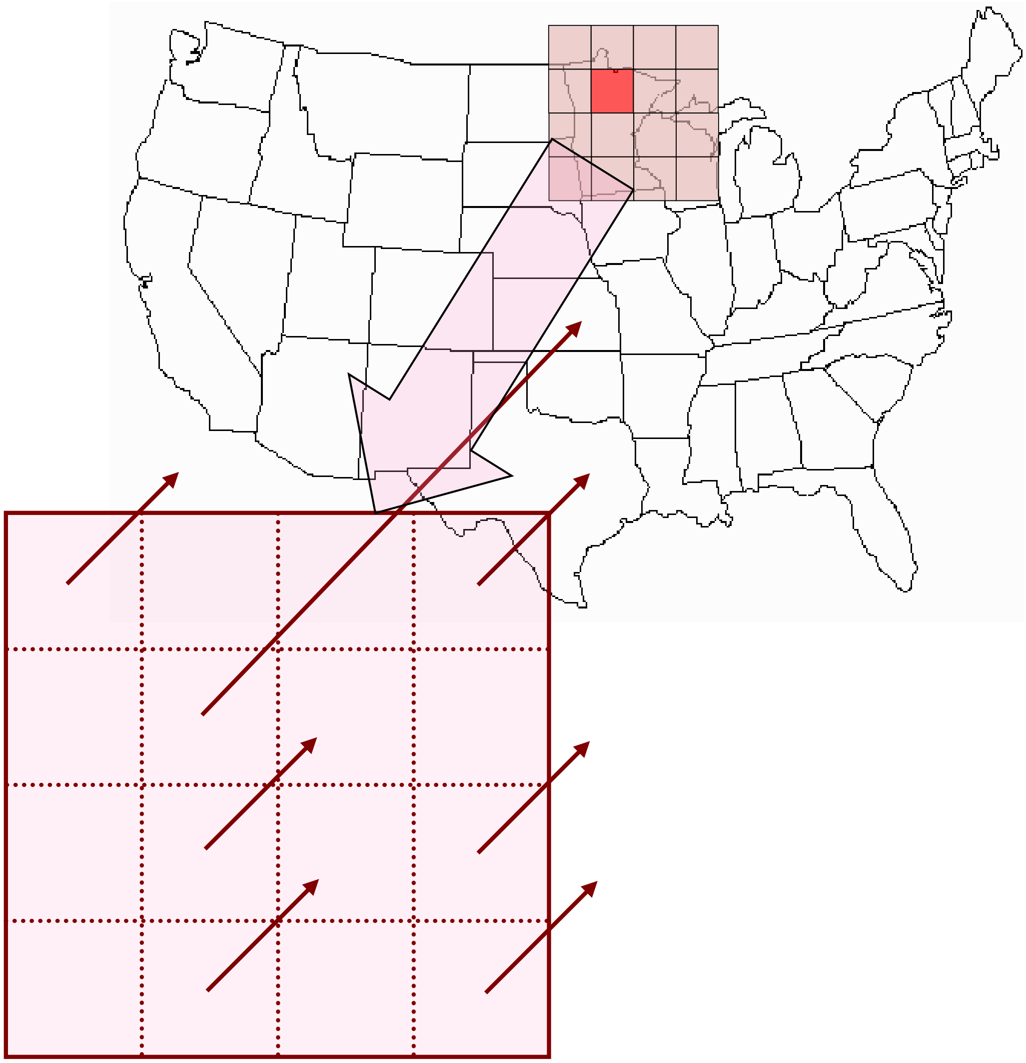


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

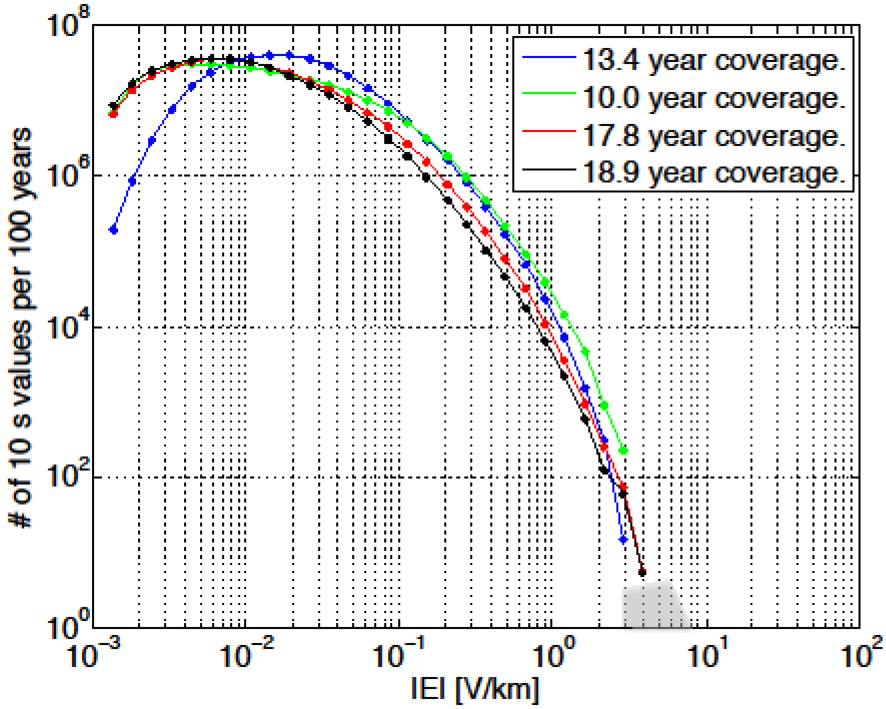


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

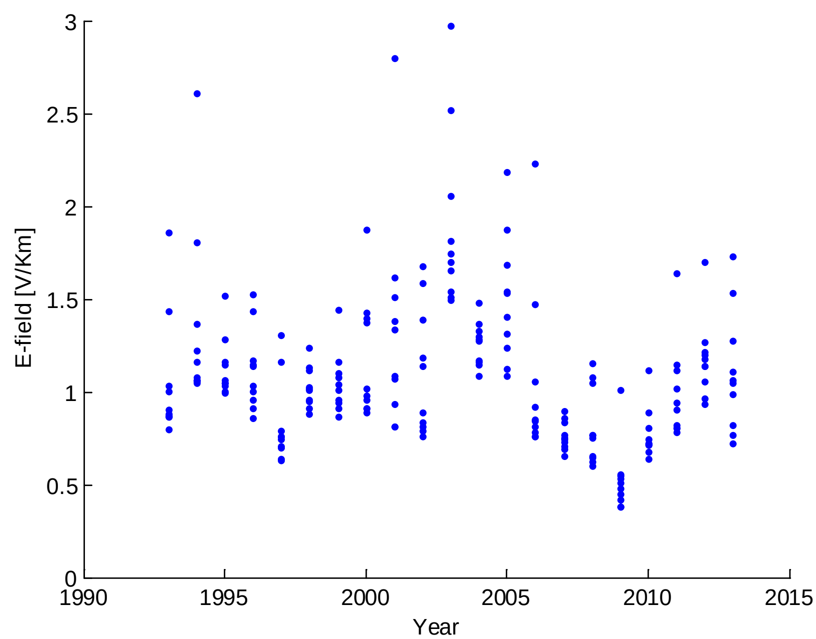


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	100 Year Return Level 95% CI [V/km]	100 Year Return Level 95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

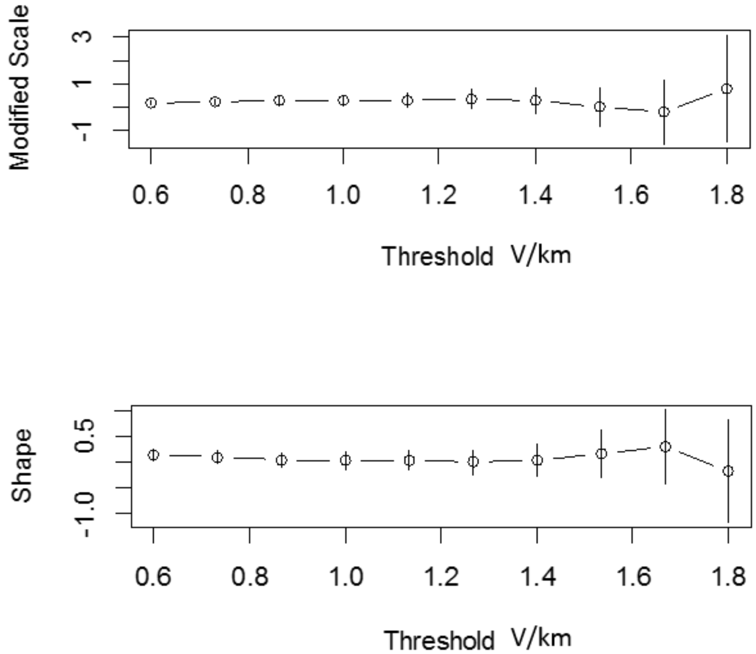


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

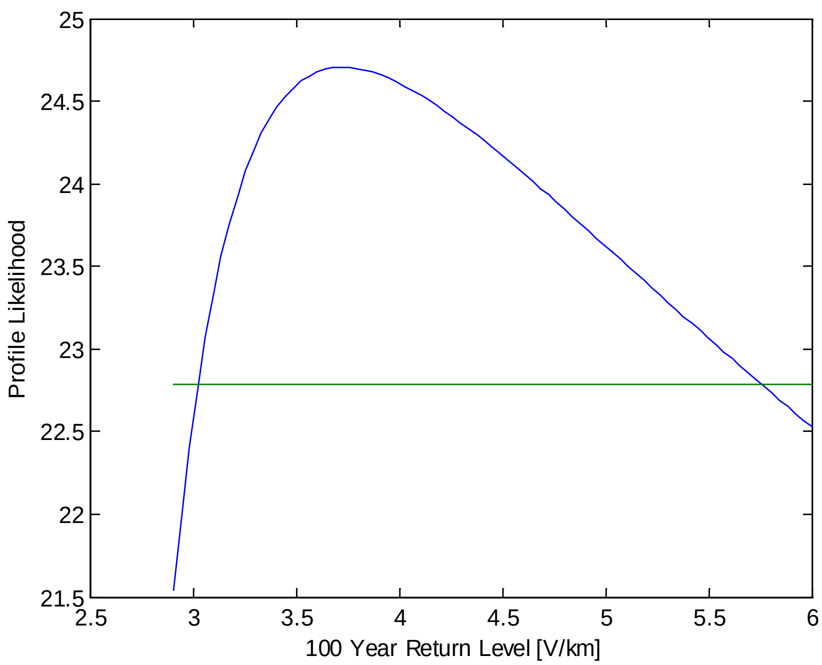


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

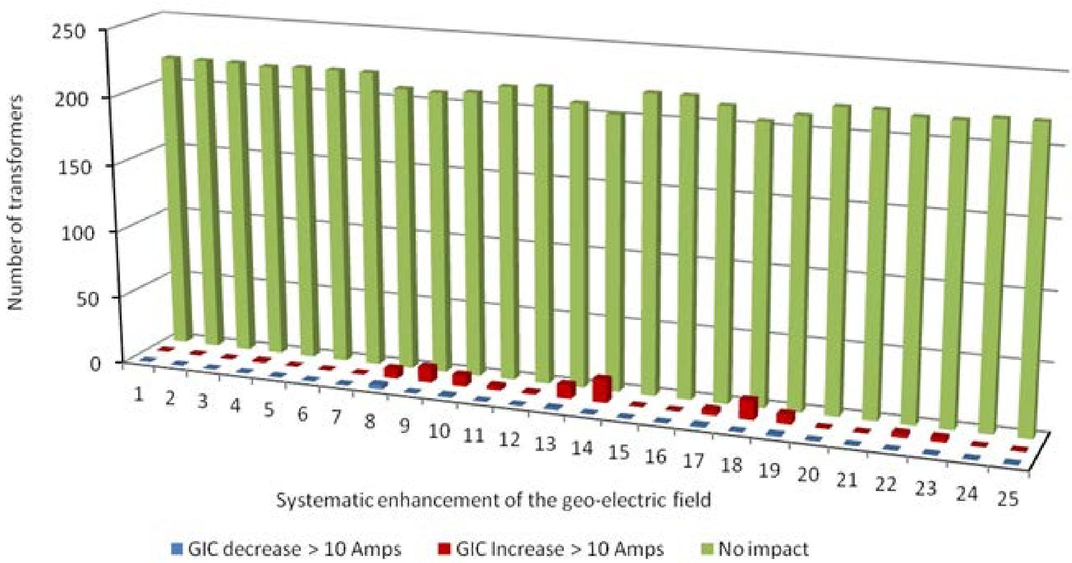


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

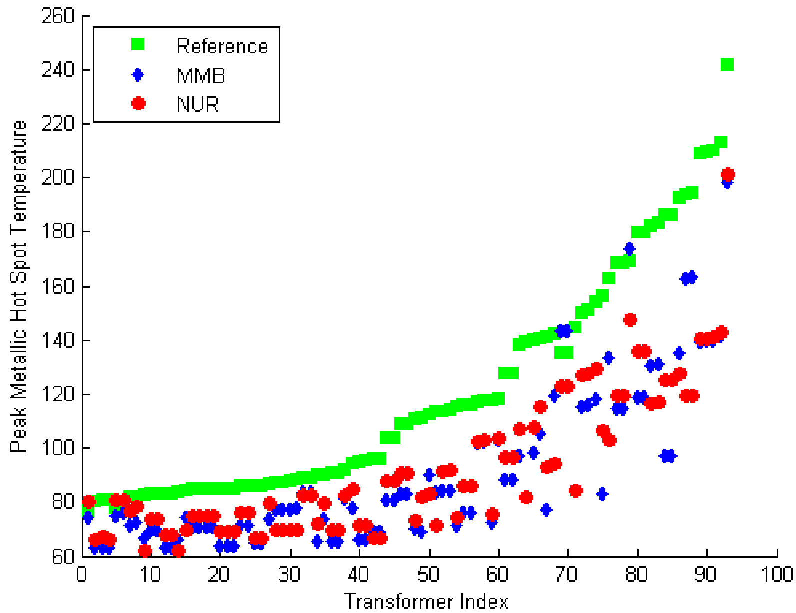


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

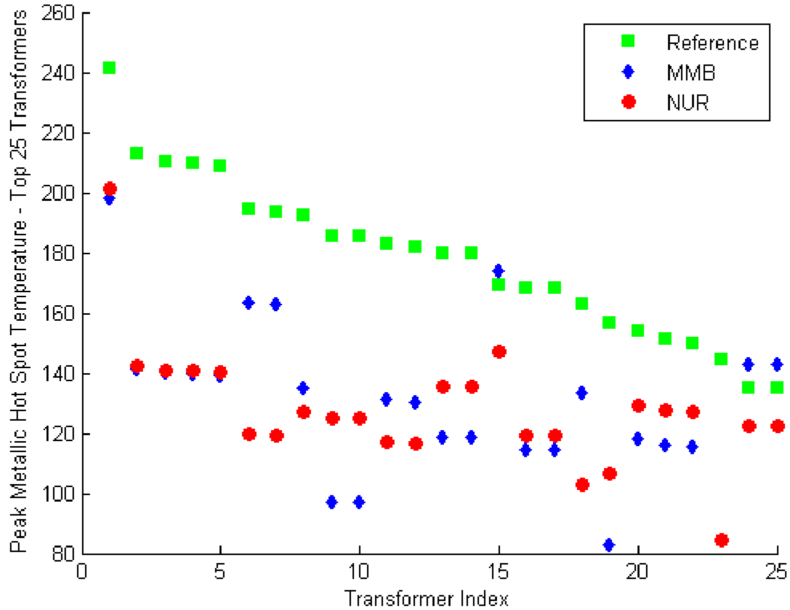


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

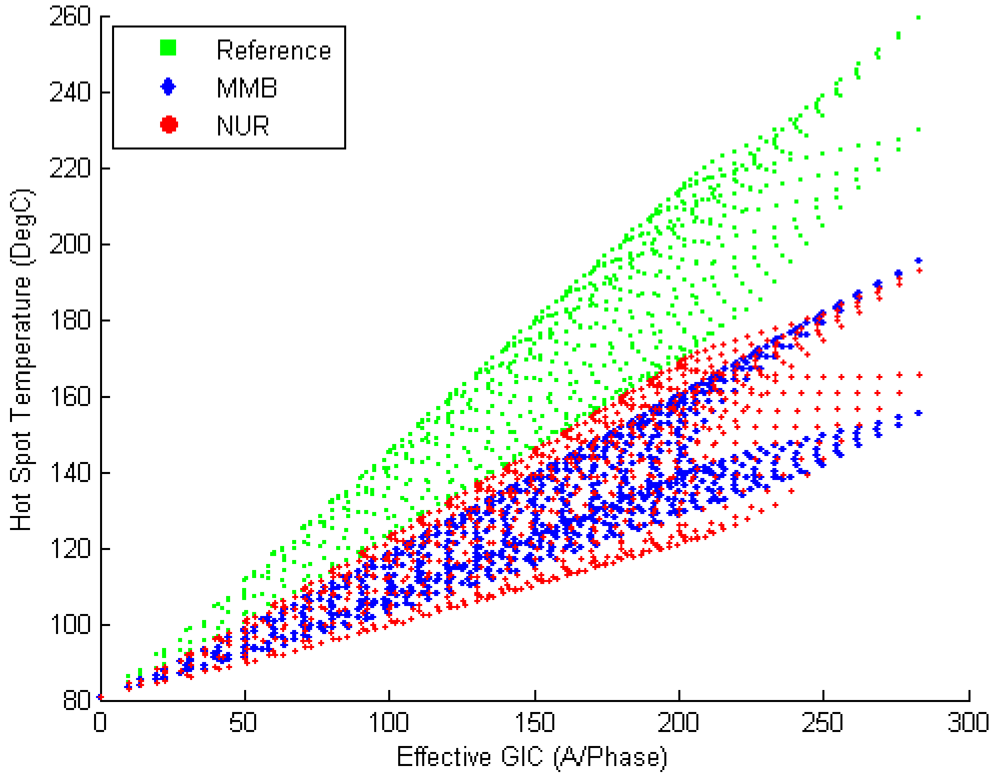


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

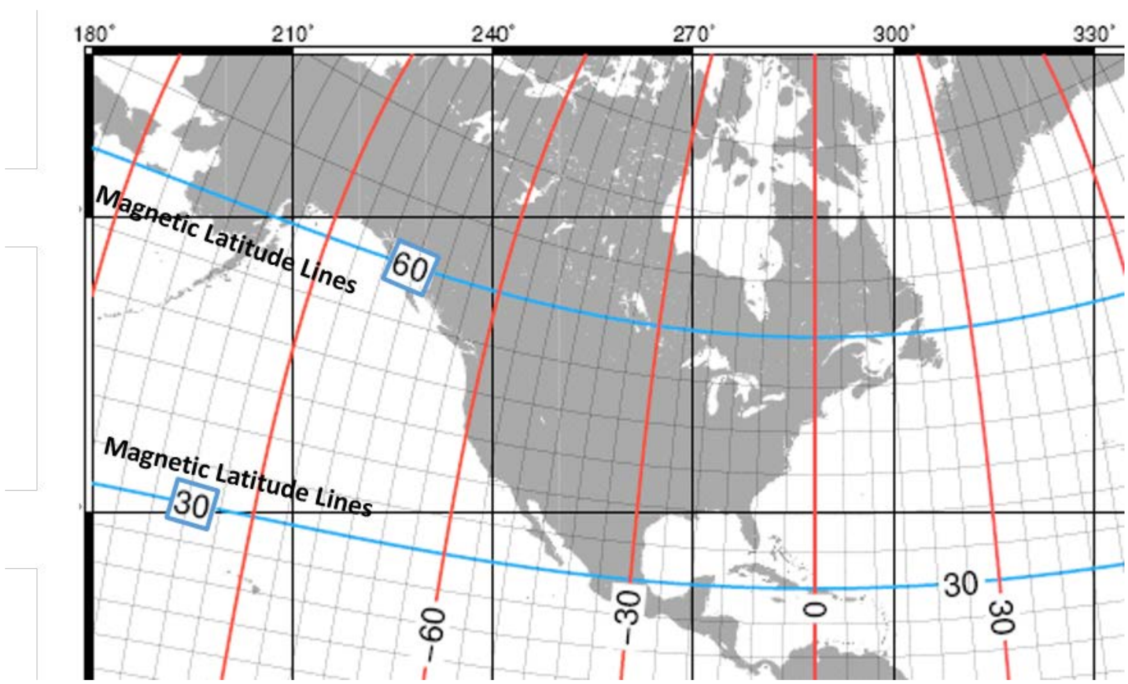


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\left\{\left|E_E(t), E_N(t)\right|\right\} \end{aligned} \qquad \text{(II.2)}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)$| are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

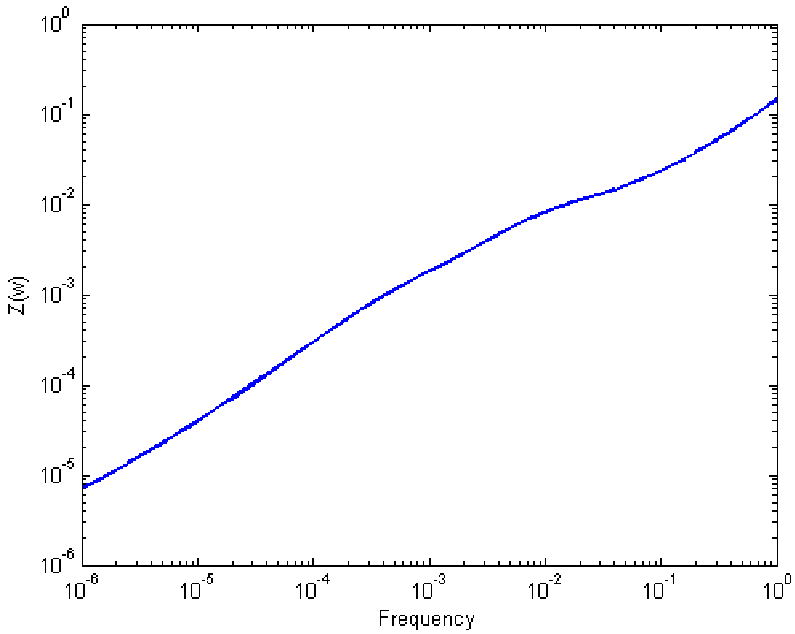


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

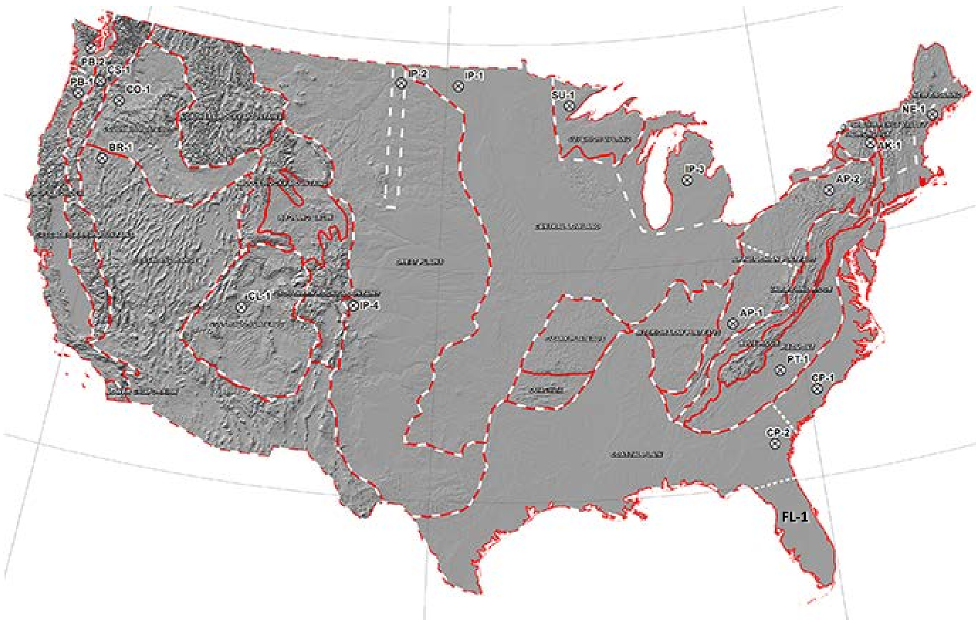
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use the largest β factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

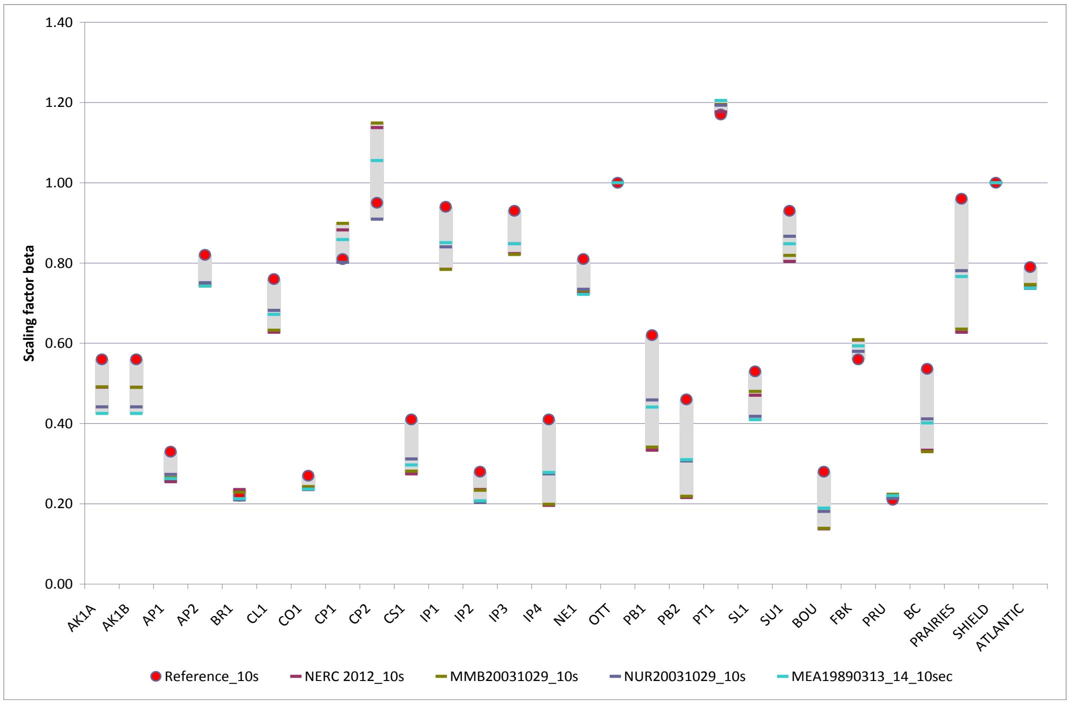


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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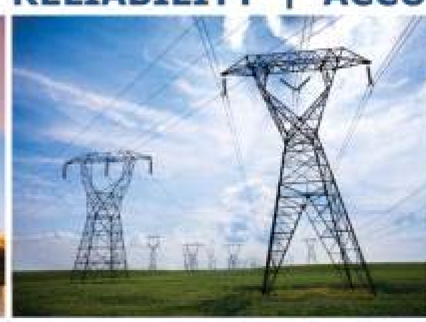
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team

~~Draft: October~~ December ~~27~~5, 2014

RELIABILITY | ACCOUNTABILITY



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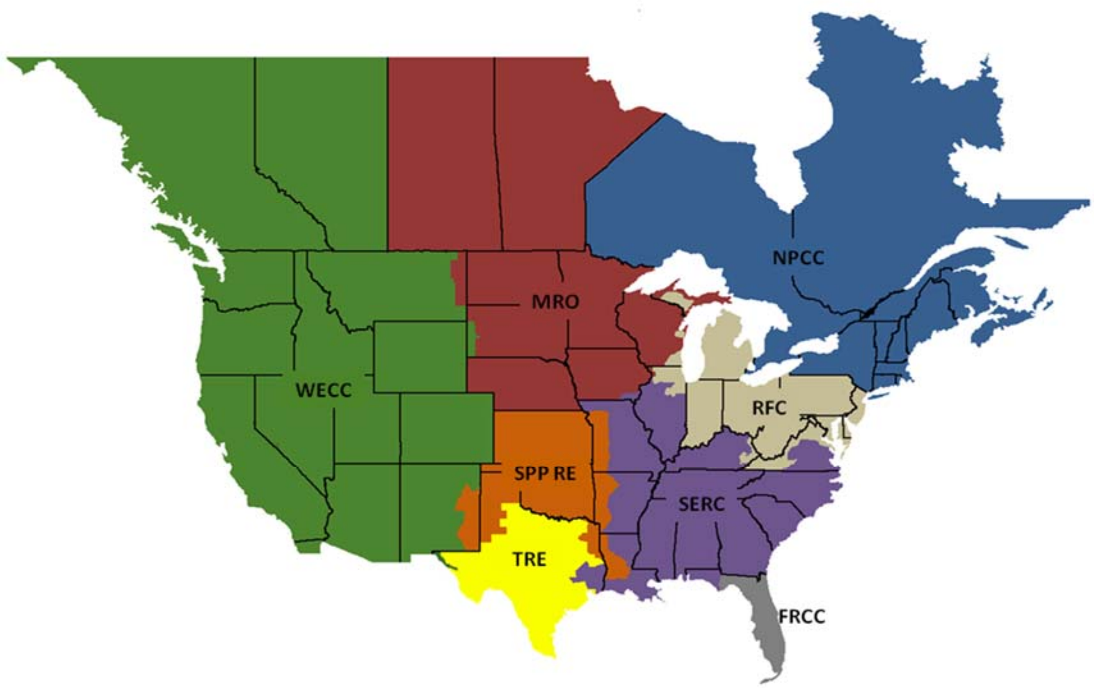
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. 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 to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)	
Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

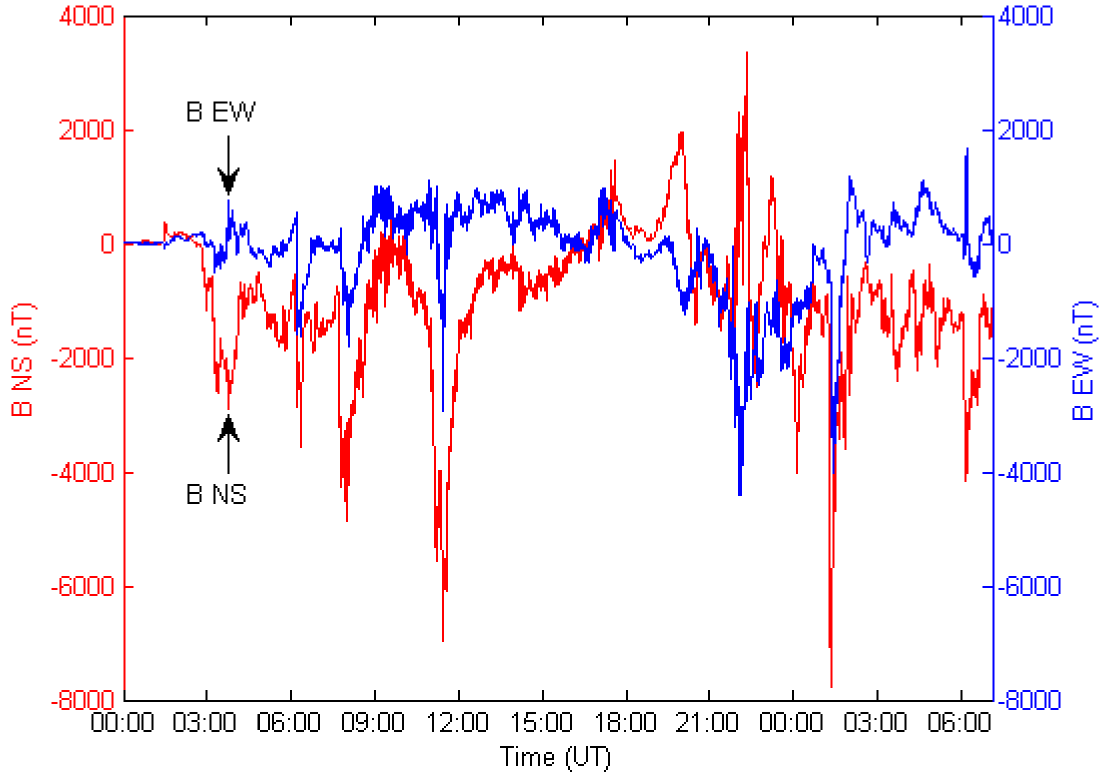


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

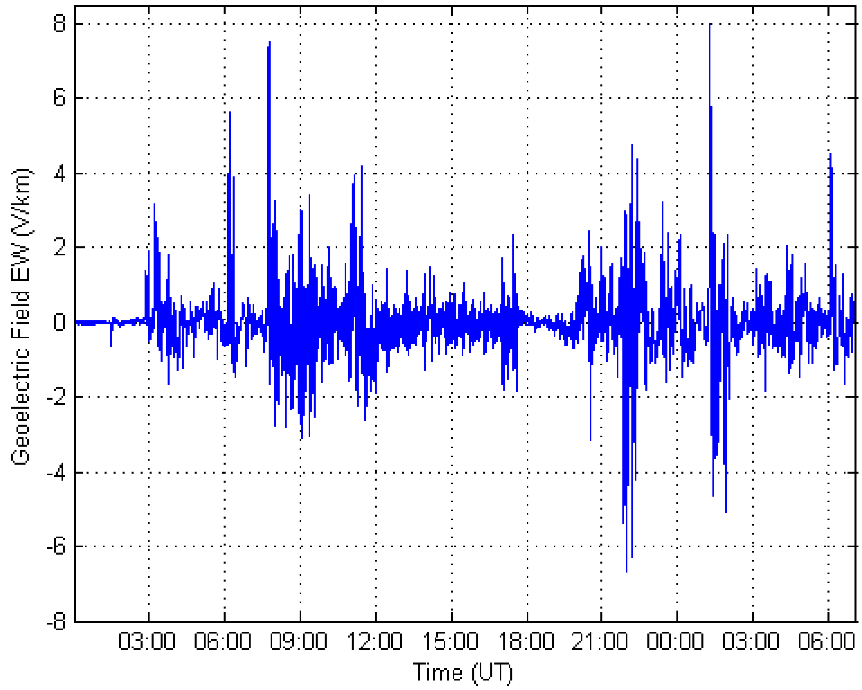


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

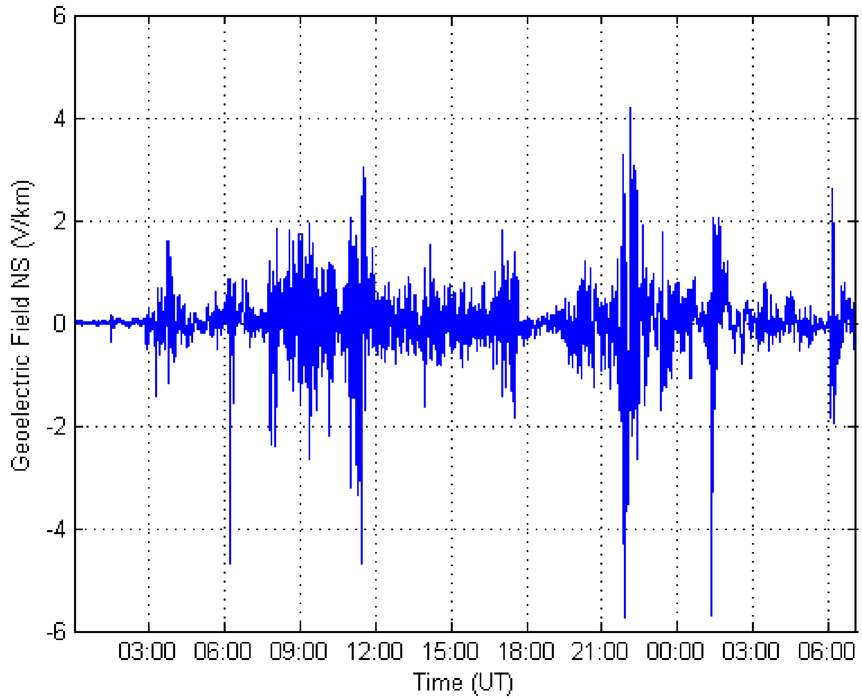


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2]**Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

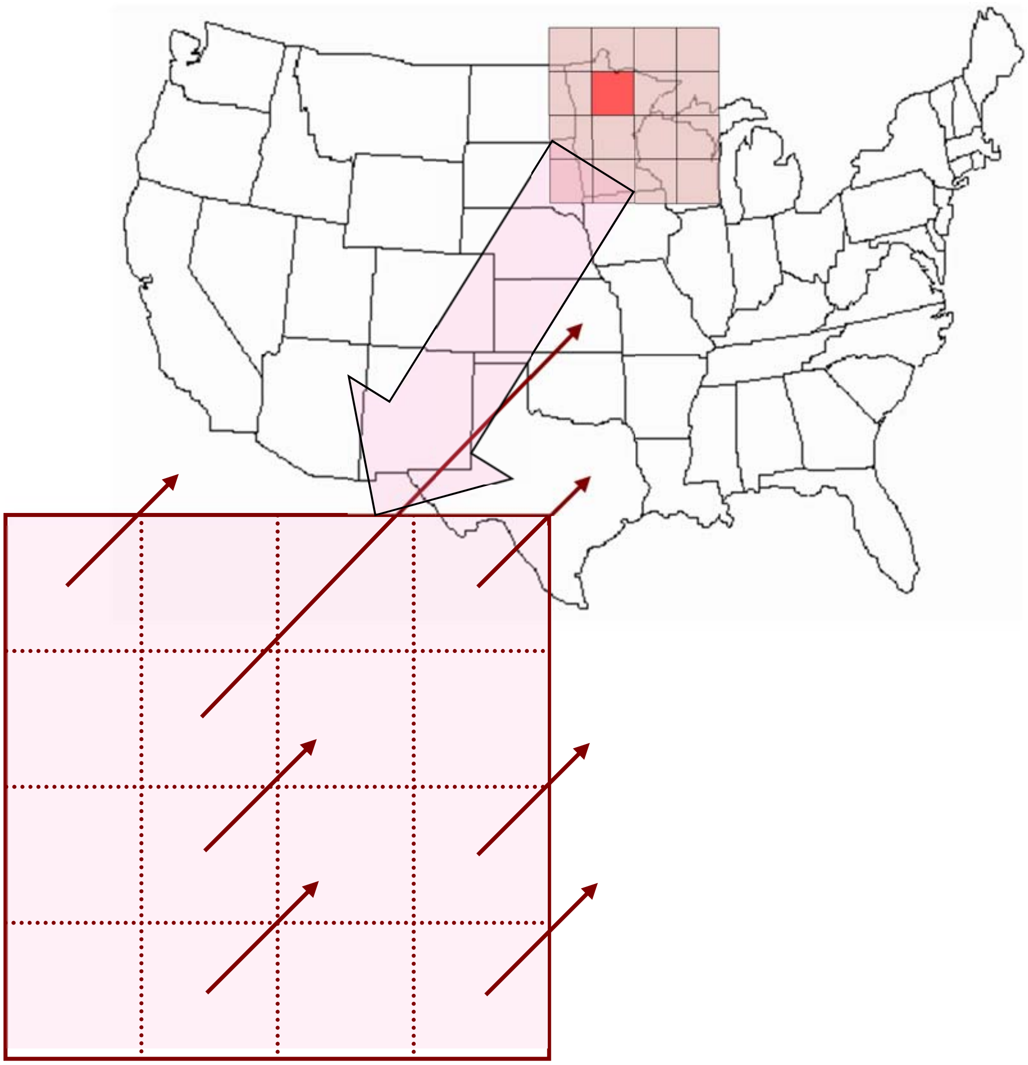


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.

In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

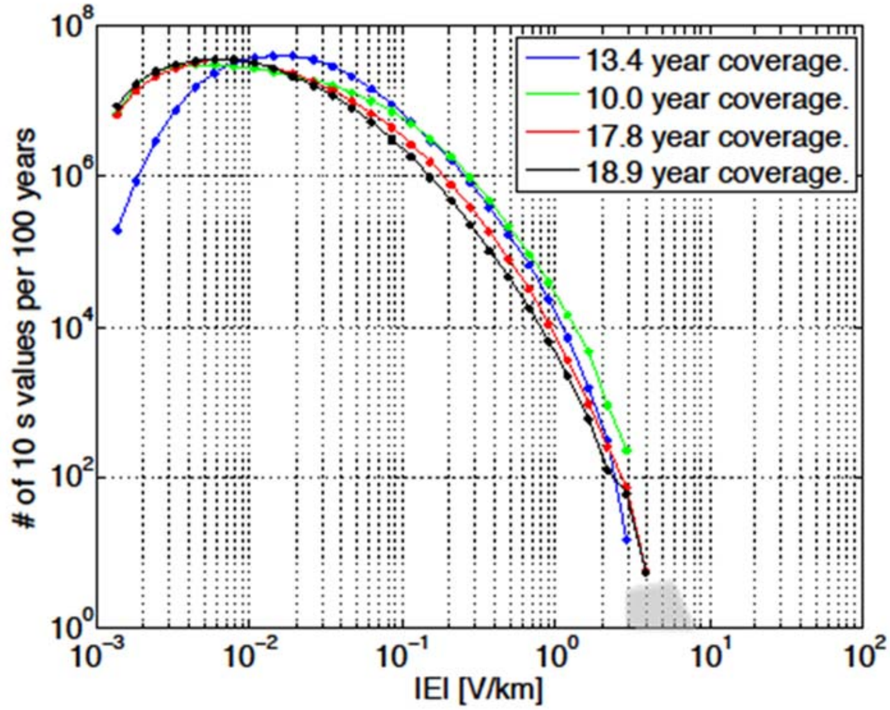


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

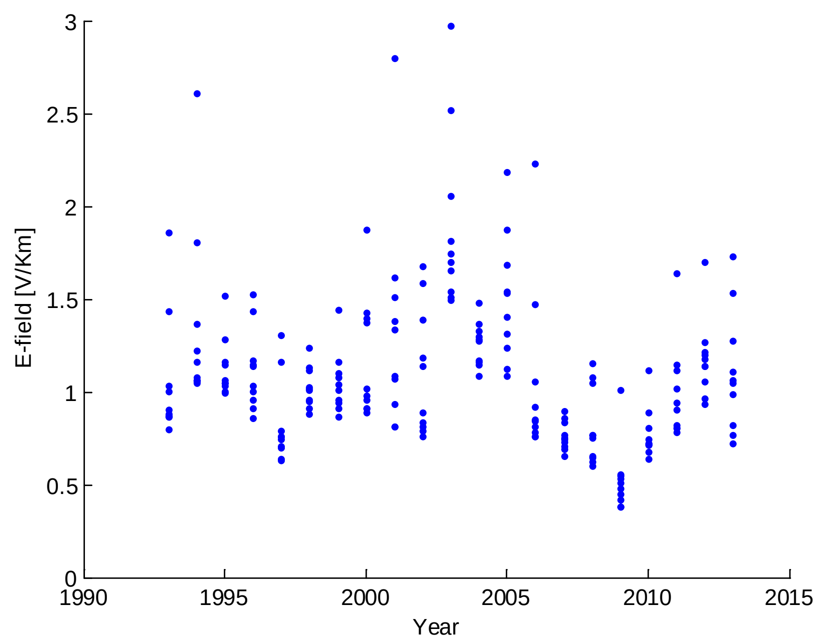


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period (365.25 · 11), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: α_1=0, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

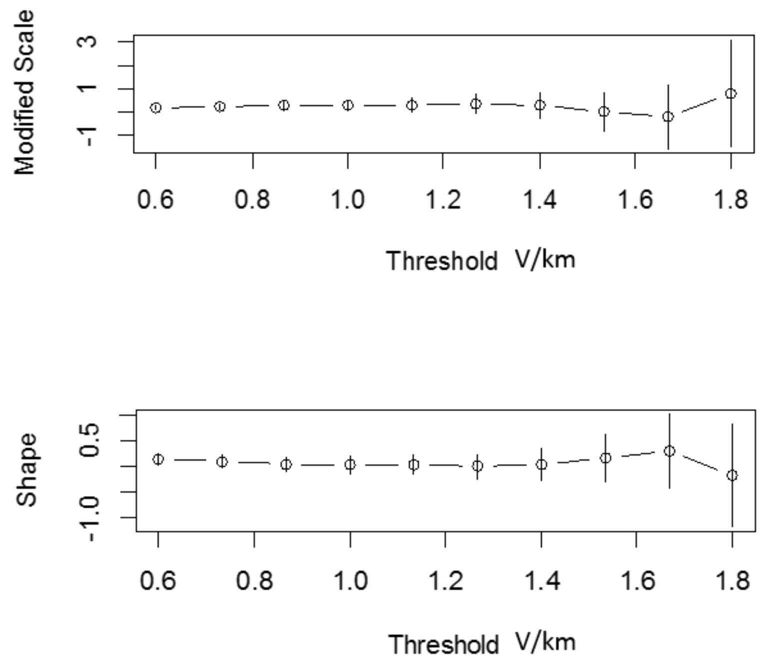


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

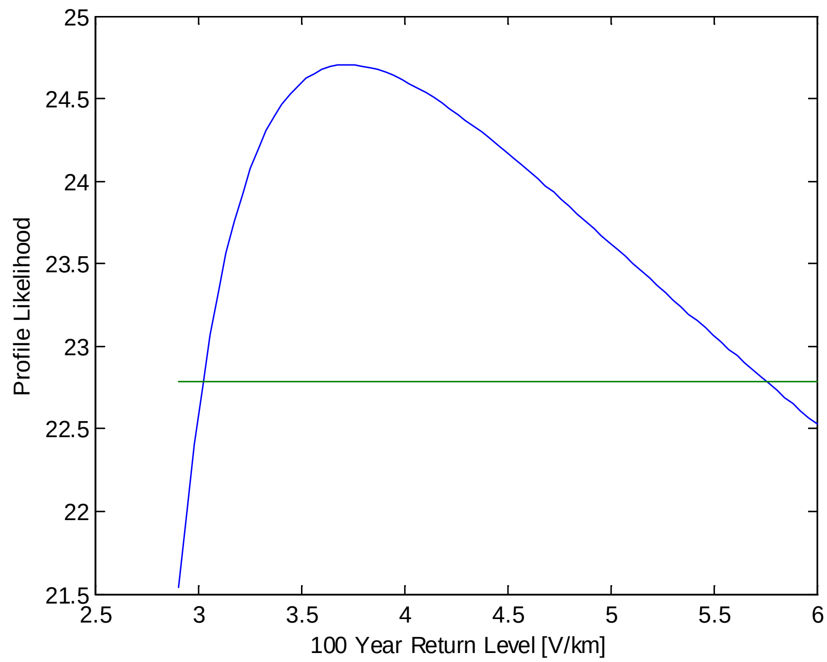


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

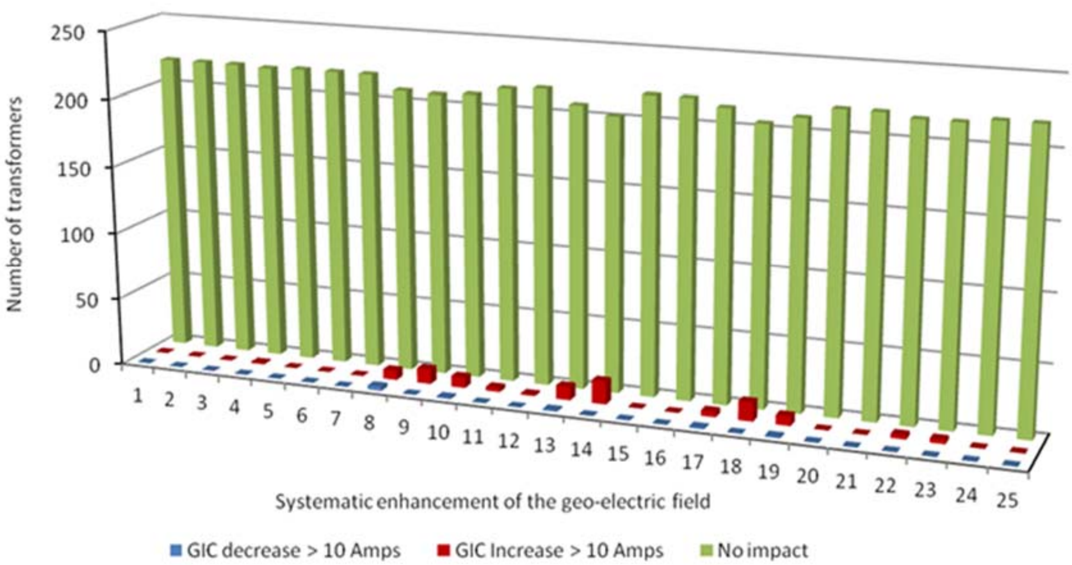


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the reference storm of the NERC interim report of 2012 [14], and measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the “Halloween event” of October 29-31, 2003.

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

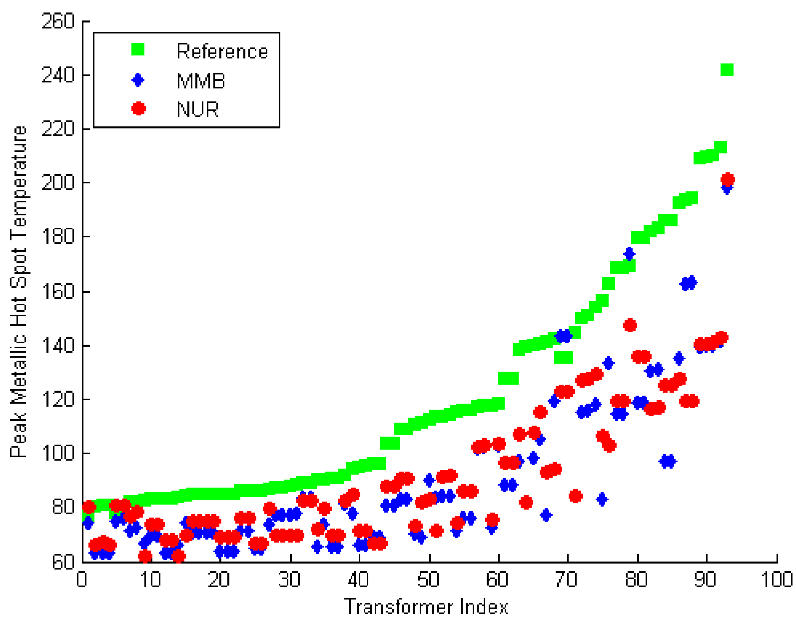


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

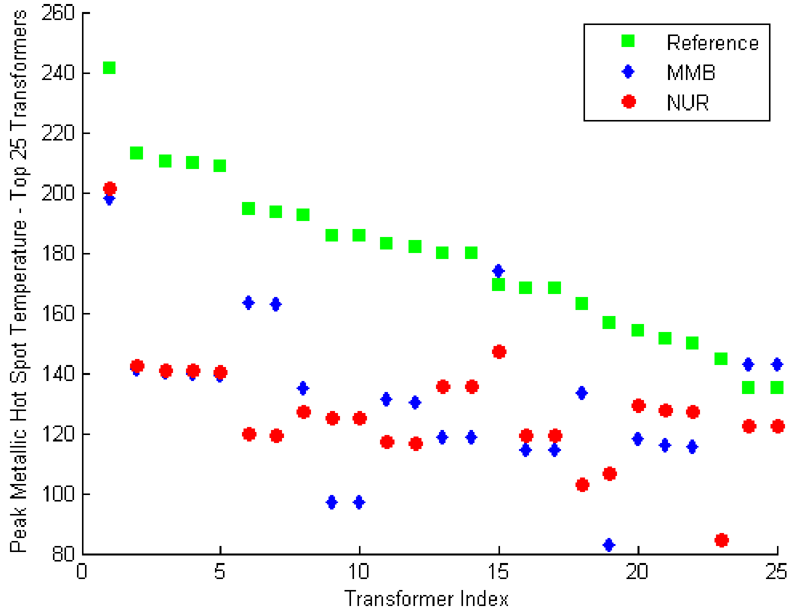


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

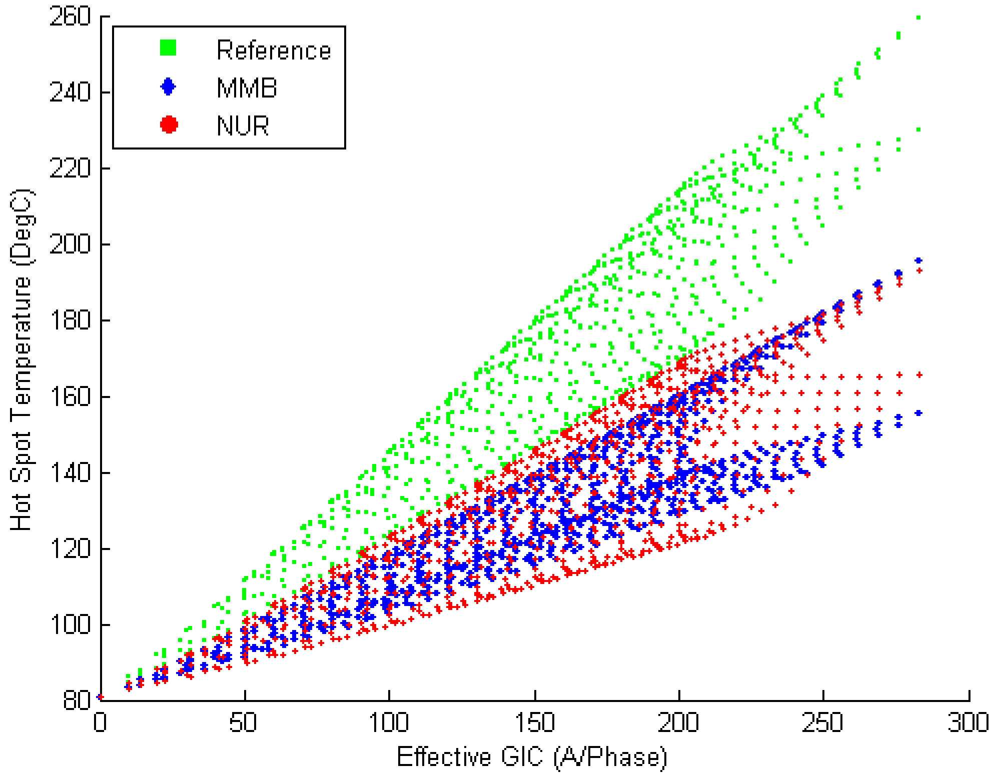


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]. Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

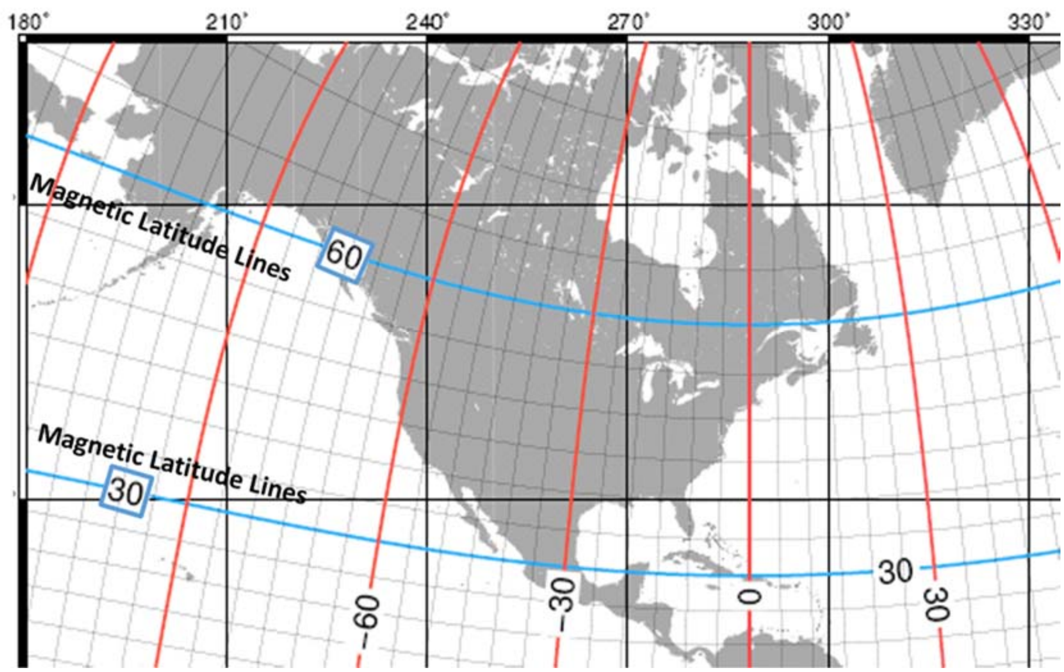


Figure II-1: Geomagnetic Latitude Lines in North America

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[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$\begin{aligned} E_N &= (z(t)/\mu_o) * B_E(t) \\ E_E &= -(z(t)/\mu_o) * B_N(t) \\ E_{peak} &= \max\{|E_E(t), E_N(t)|\} \end{aligned} \qquad \text{(II.2)}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

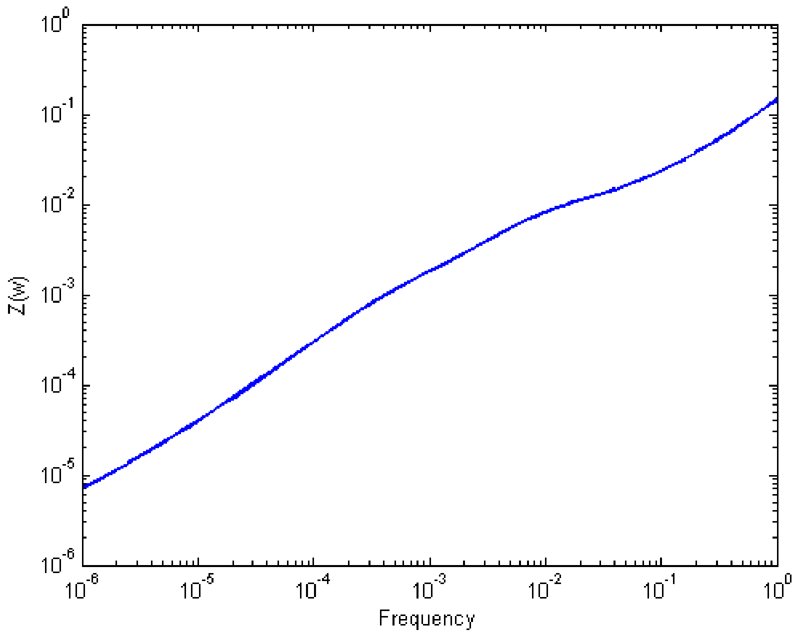


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

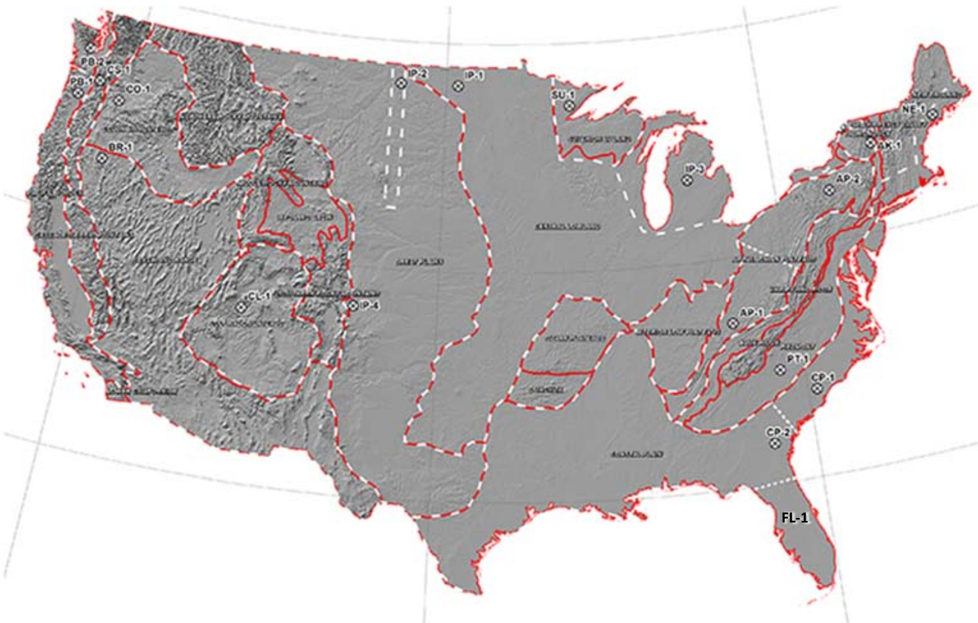
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \tag{II.3}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- When a ground conductivity model is not available the planning entity should use the largest β factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	**Scaling Factor (β)**
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

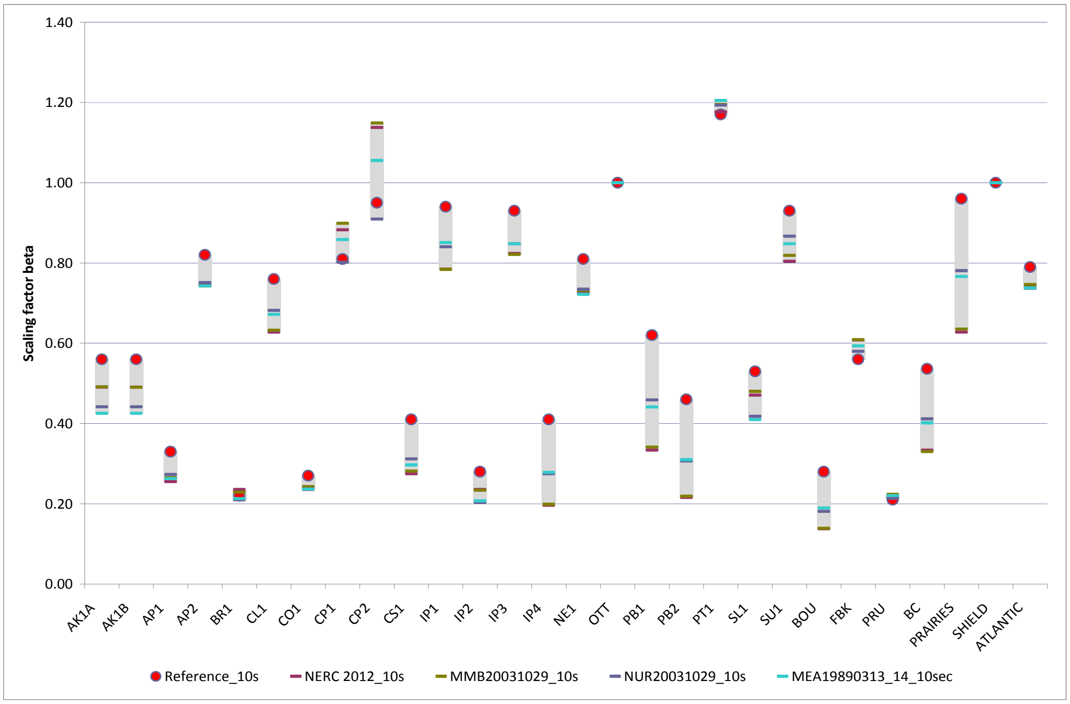


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5V / km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

References

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Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

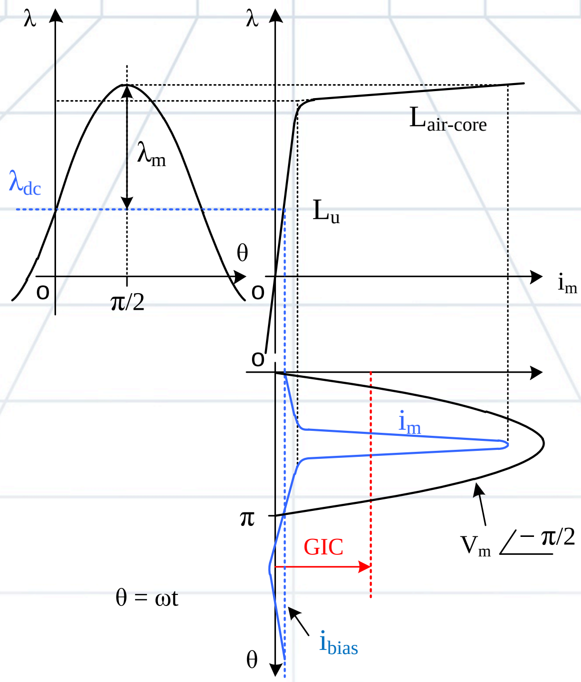

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N / 3 - I_H) V_X / V_H \tag{1}$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as **Table 1** below, provides the peak metallic hot spot temperatures that can be reached using conservative screening thermal models. To use **Table 1**, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer

capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

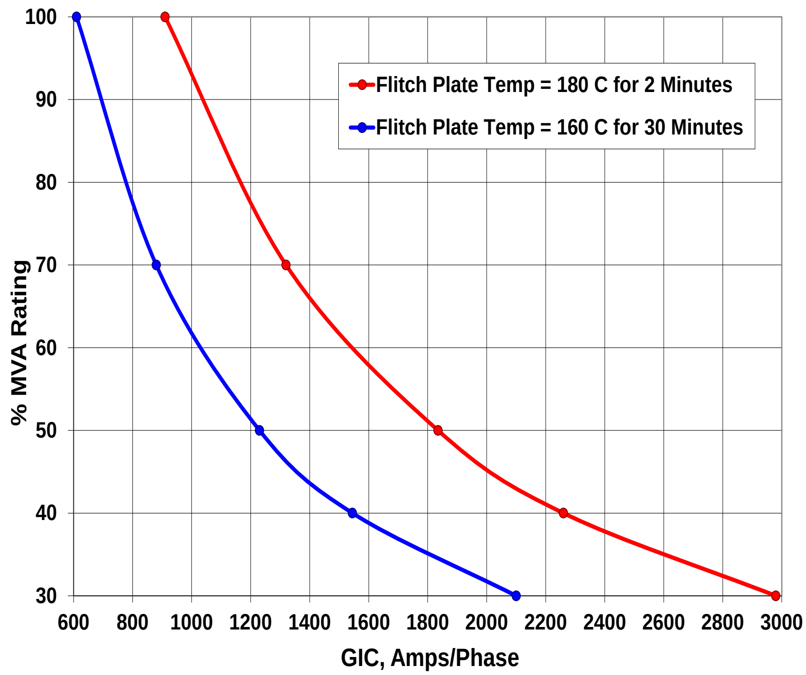

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

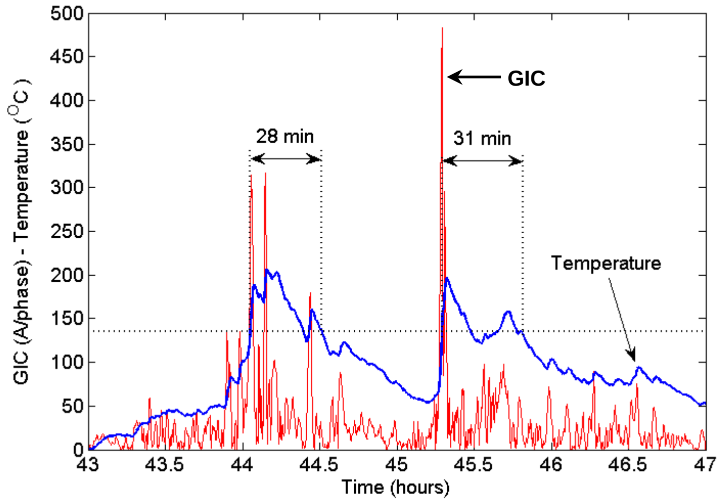

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{3}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{4}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{5}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \tag{6}$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \tag{7}$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

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[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

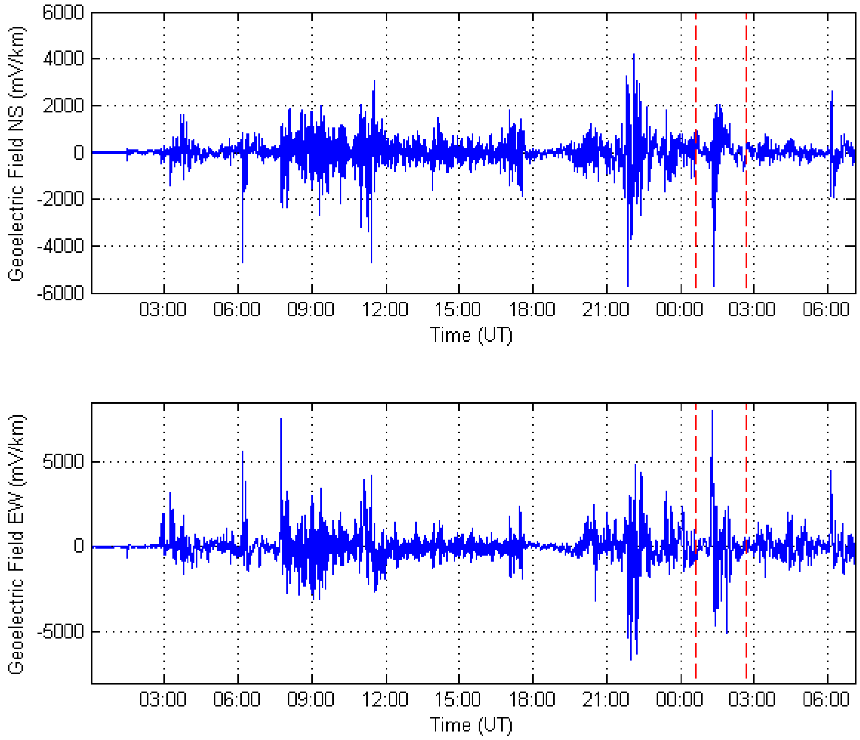

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

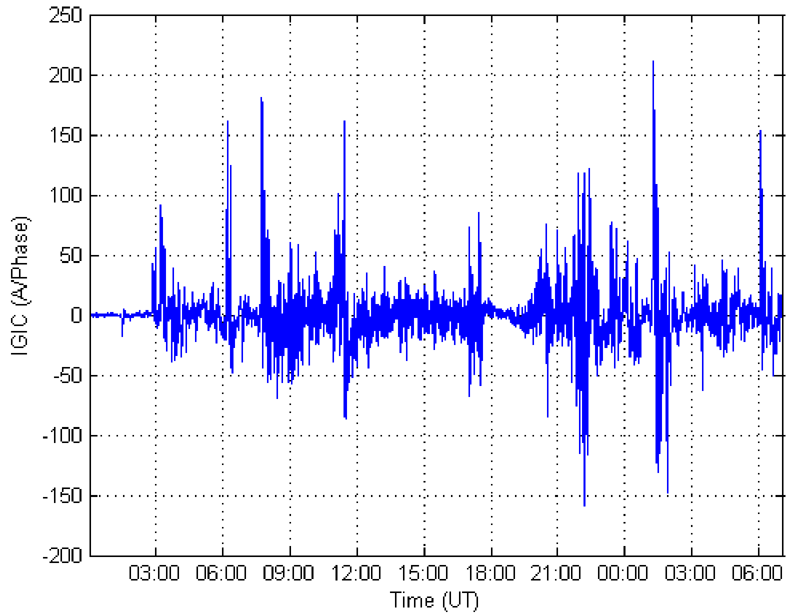

Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

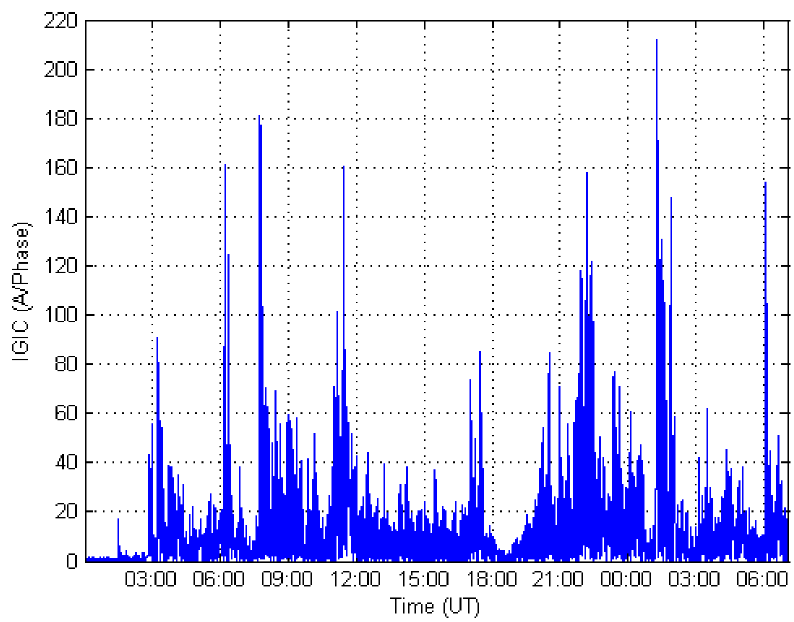

Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

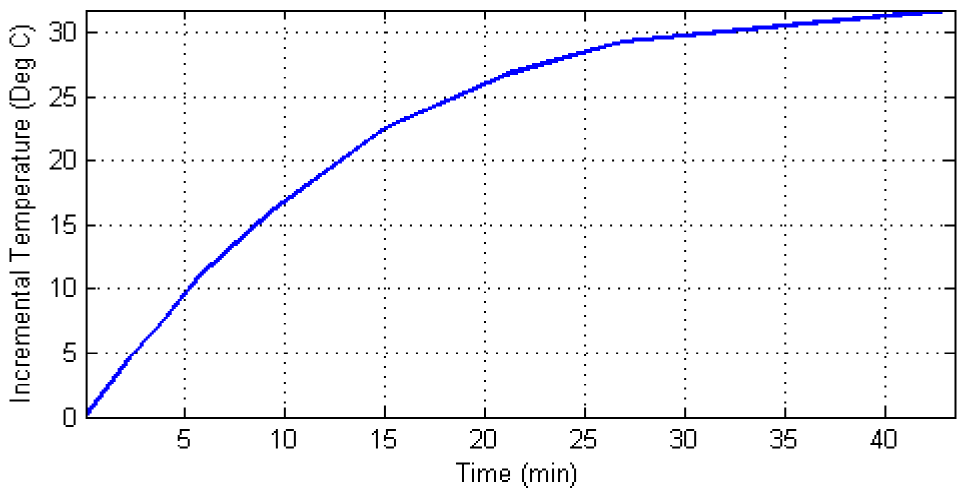

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

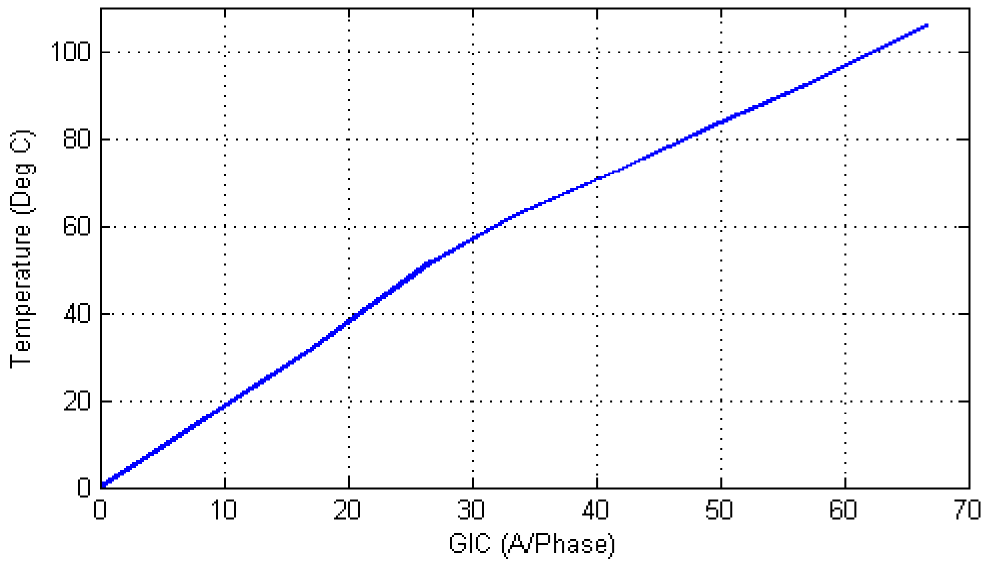

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

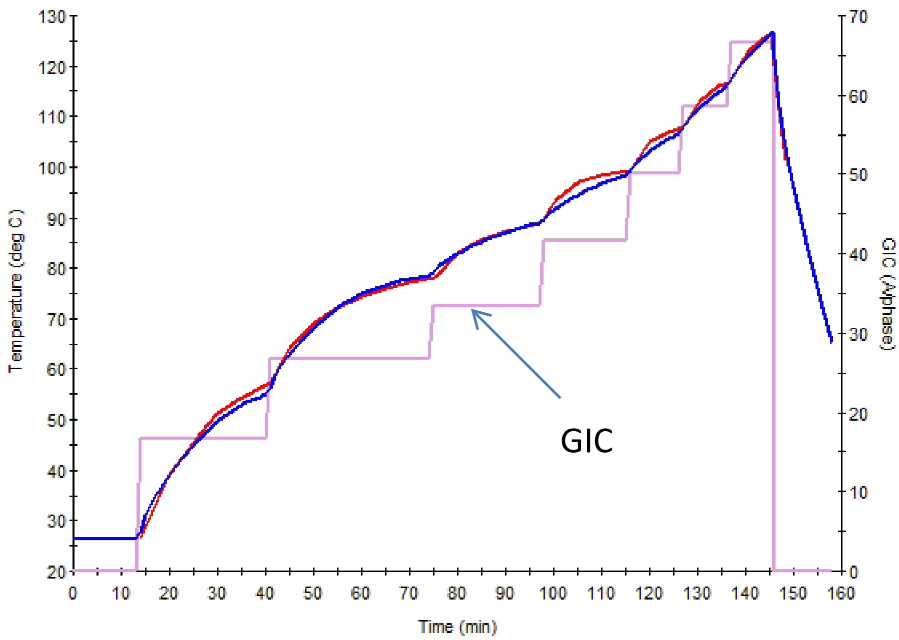

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

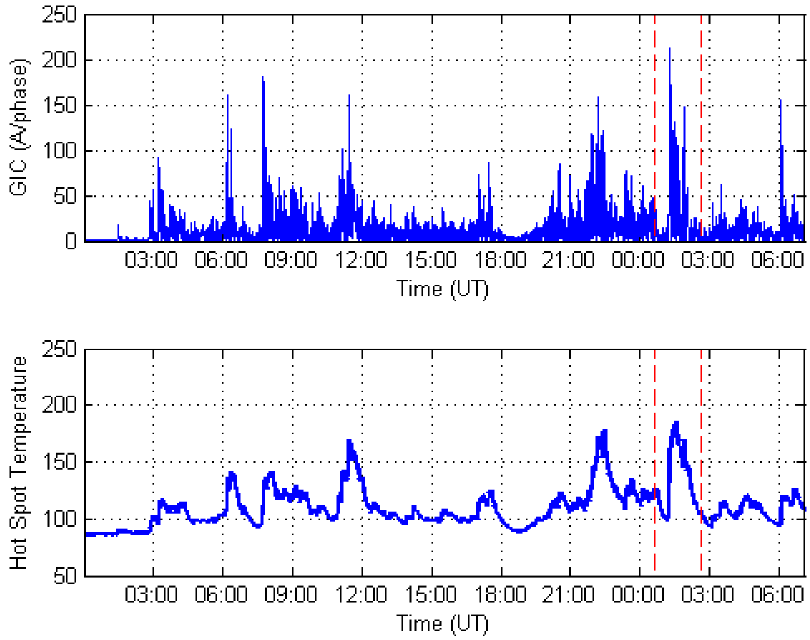

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

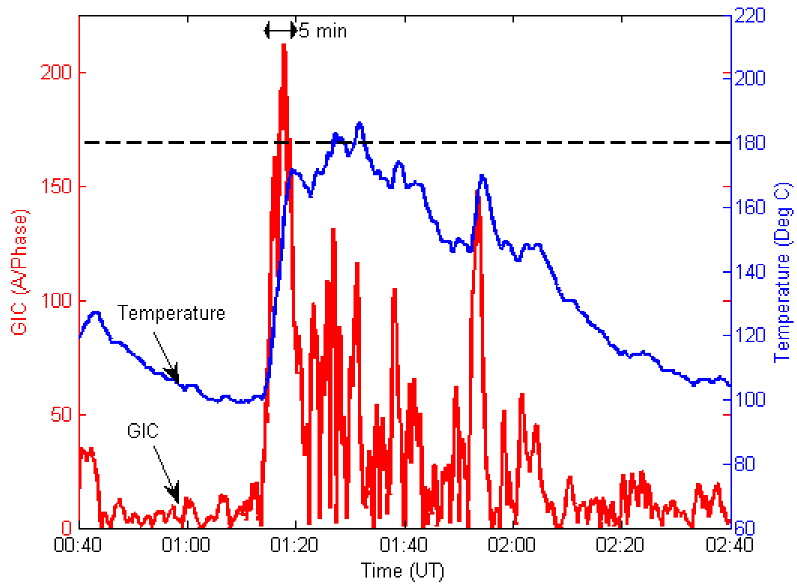

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

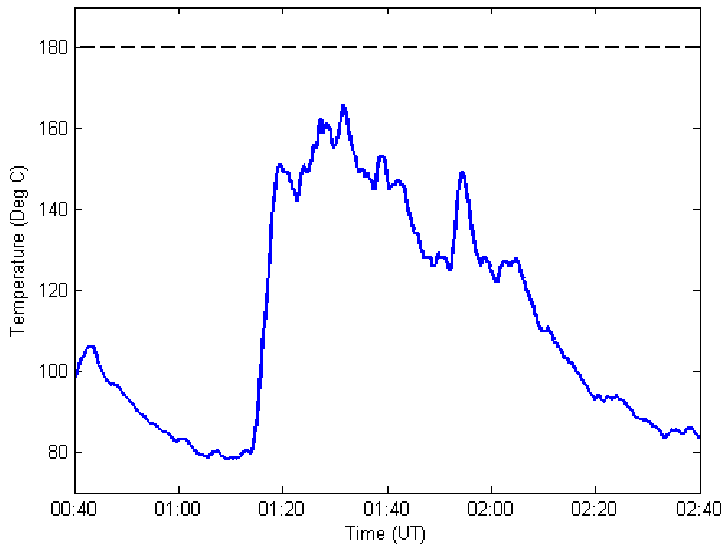

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std C57.91).

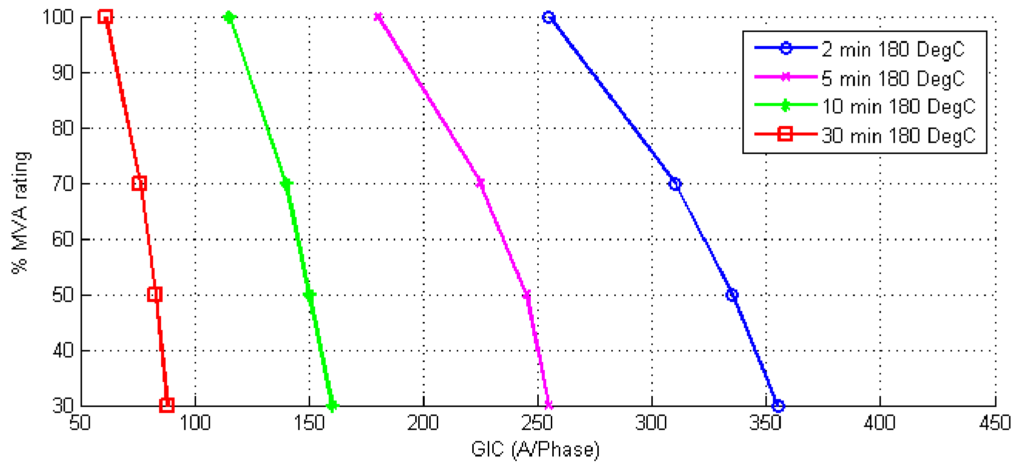

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

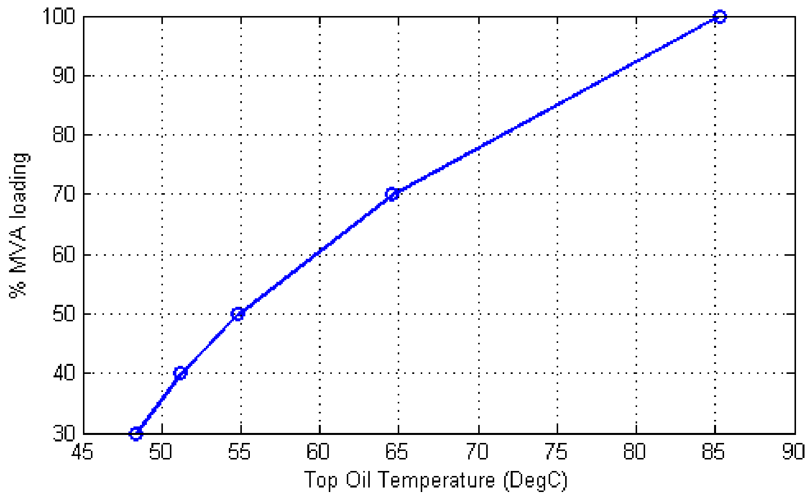

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

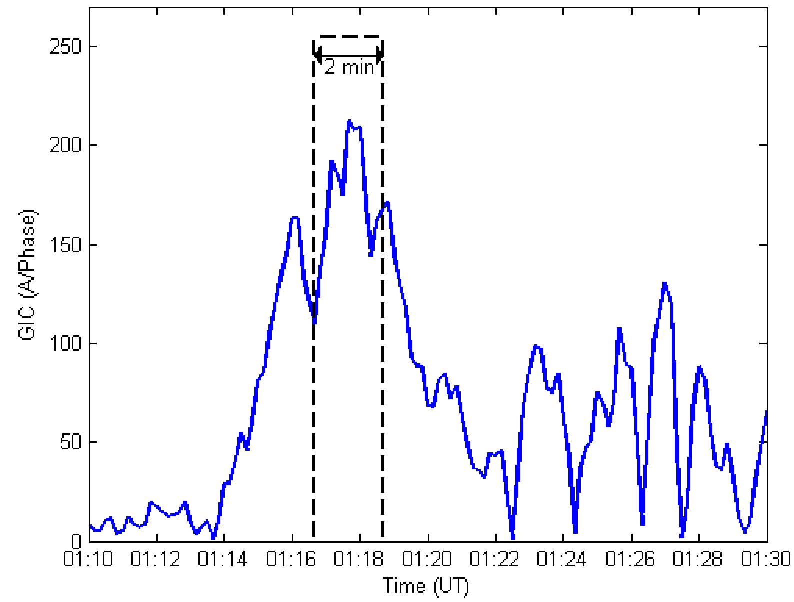

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

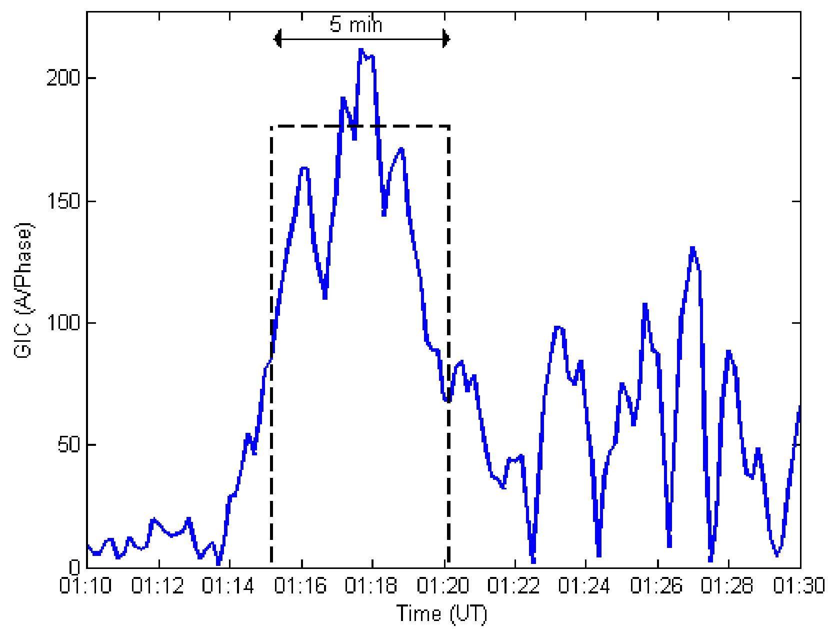

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

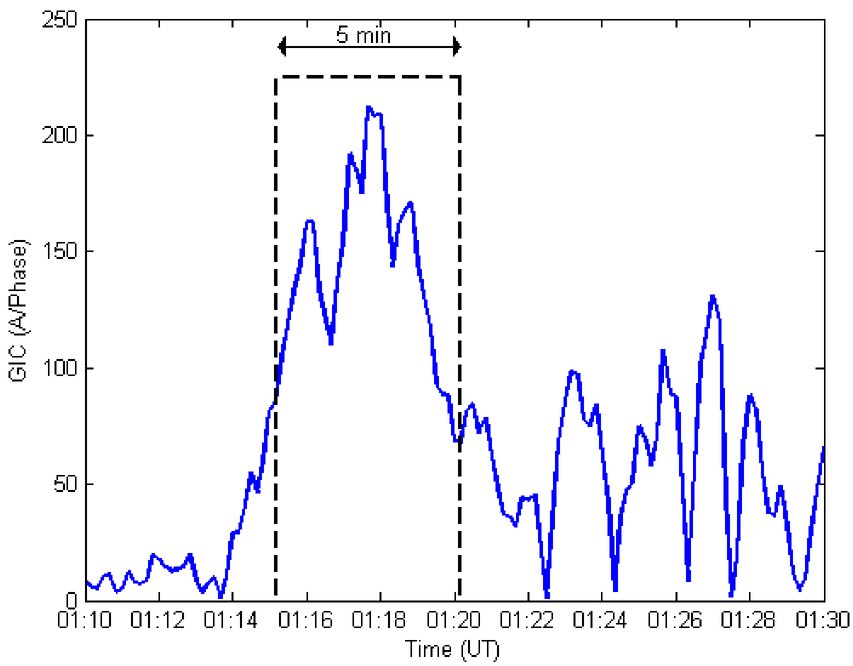

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and 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.

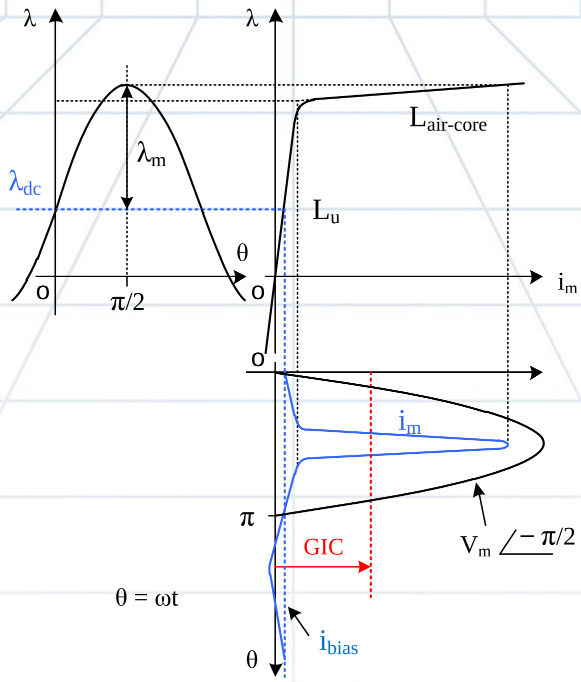

Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or “waveshape” of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The “effective” GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H \qquad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the “Screening Criterion for Transformer Thermal Impact Assessment” white paper [7]. This table, shown as **Table 1** below, provides the peak metallic hot spot temperatures that can be reached using conservative screening thermal models. To use **Table 1**, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer

capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

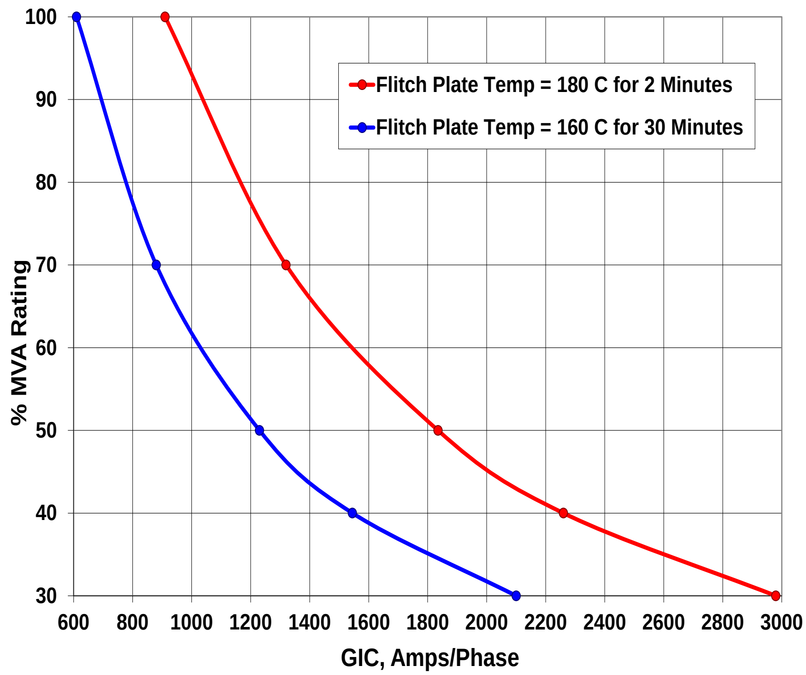

Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

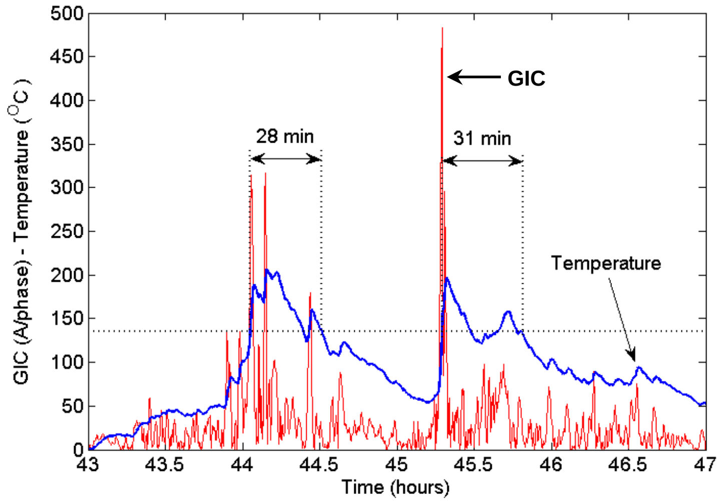

Figure 3: Sample Tie Plate Temperature Calculation

Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[2]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[3]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

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[2] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[3] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

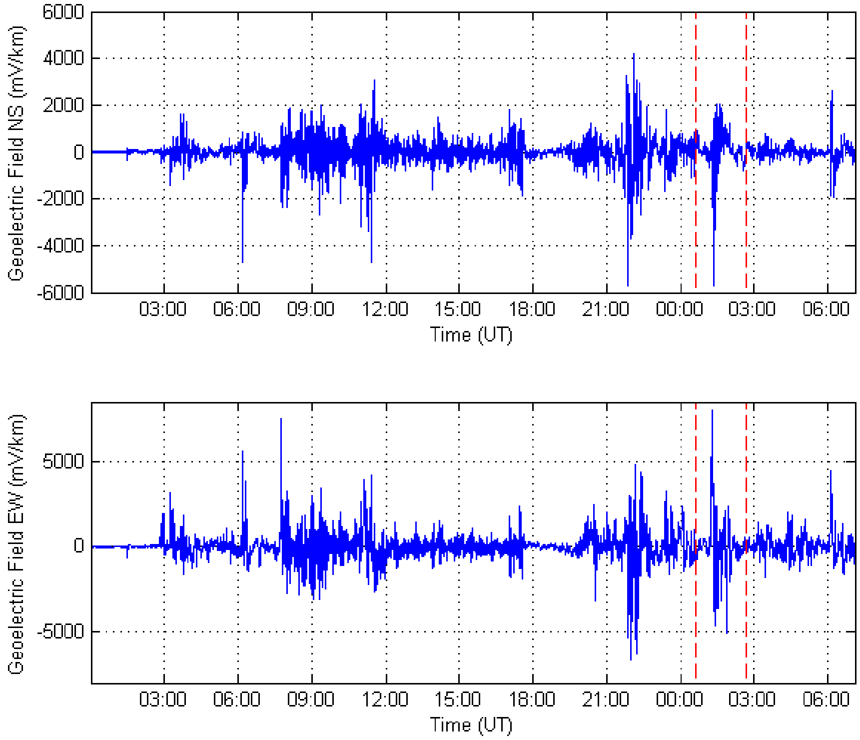

Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming α=1 and β=1 (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

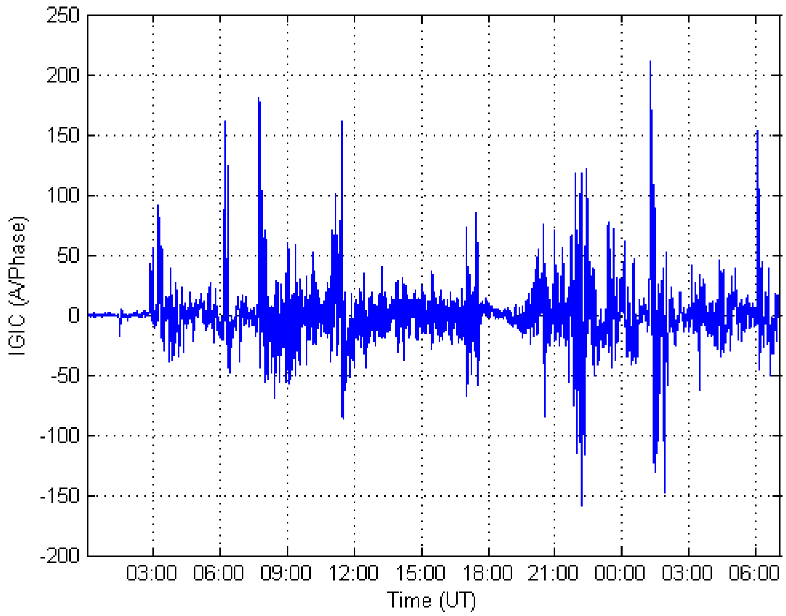

Figure 5: Calculated GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

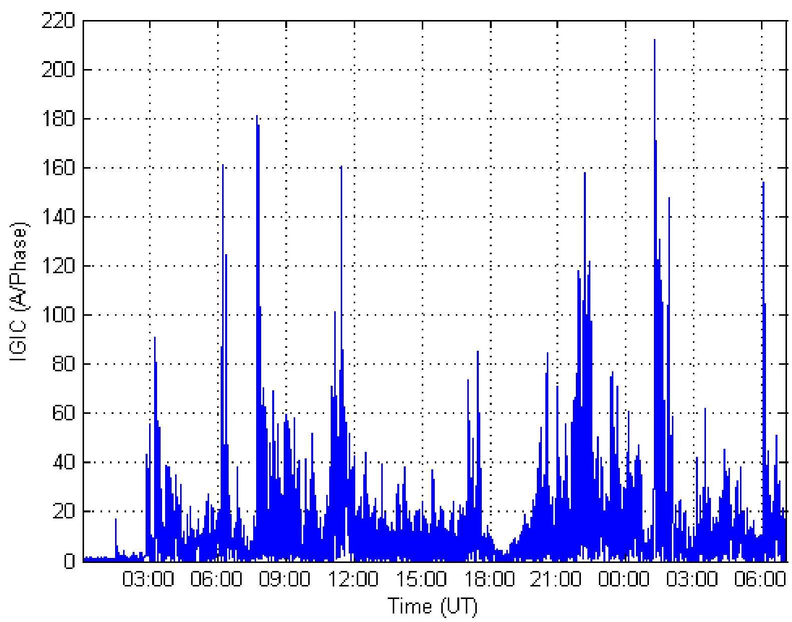

Figure 6: Calculated Magnitude of GIC(t) Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[4]

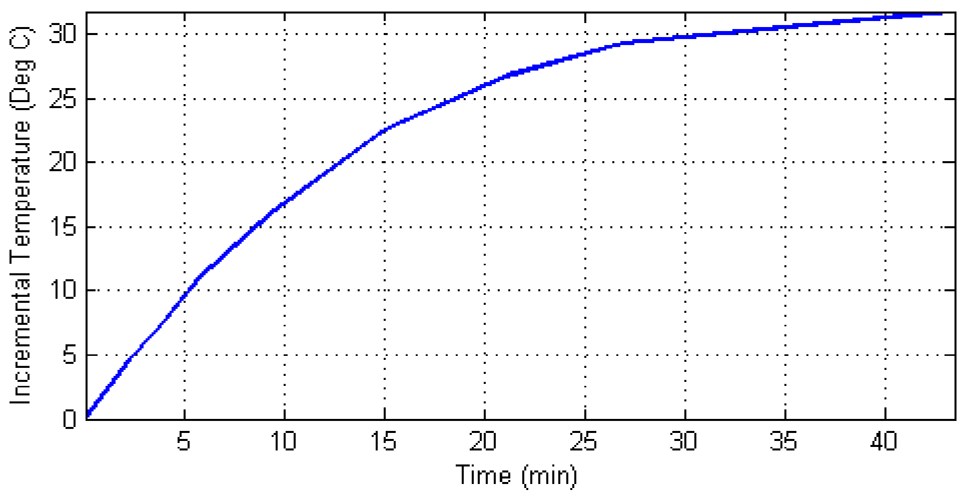

Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step

Metallic hot spot heating.

[4] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

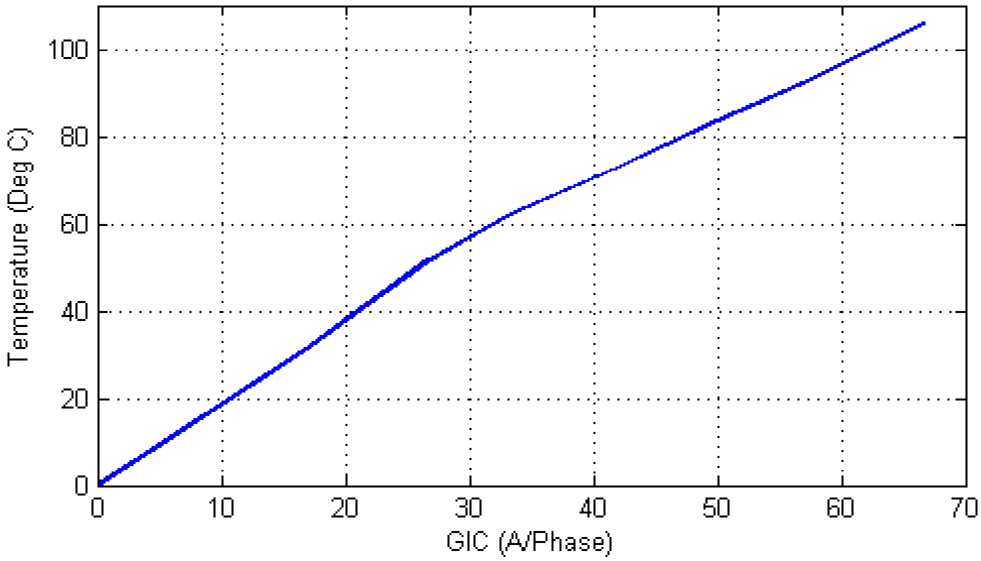

Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

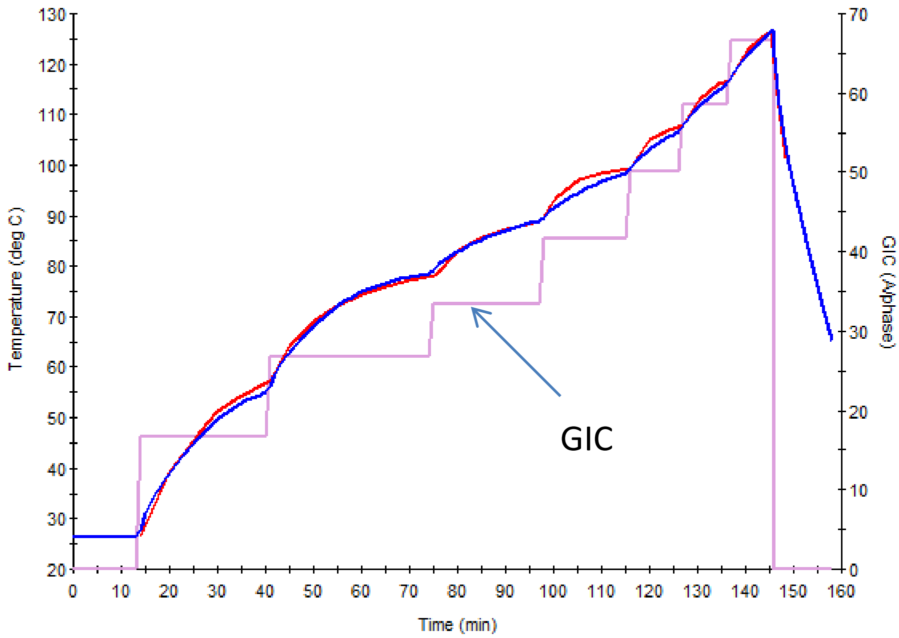

Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, 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. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time θ(t) for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

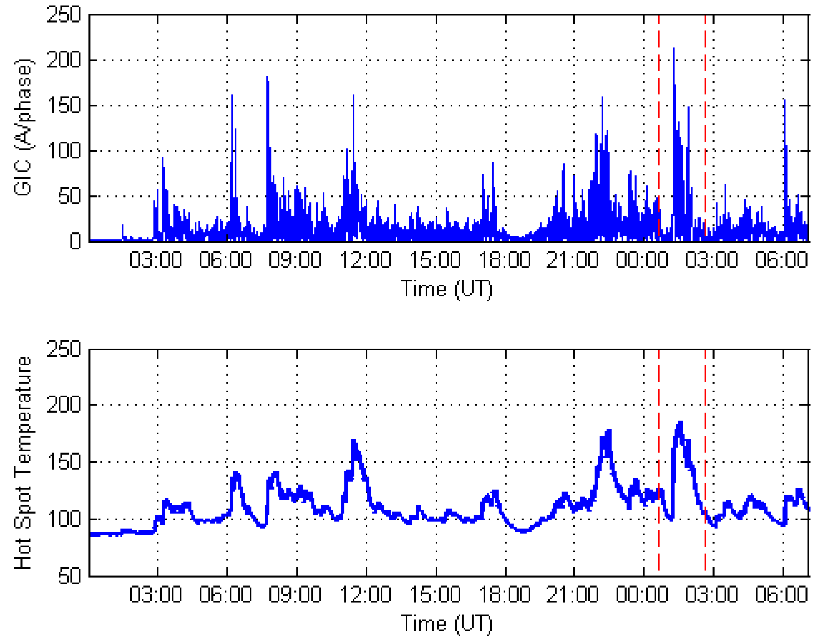

Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

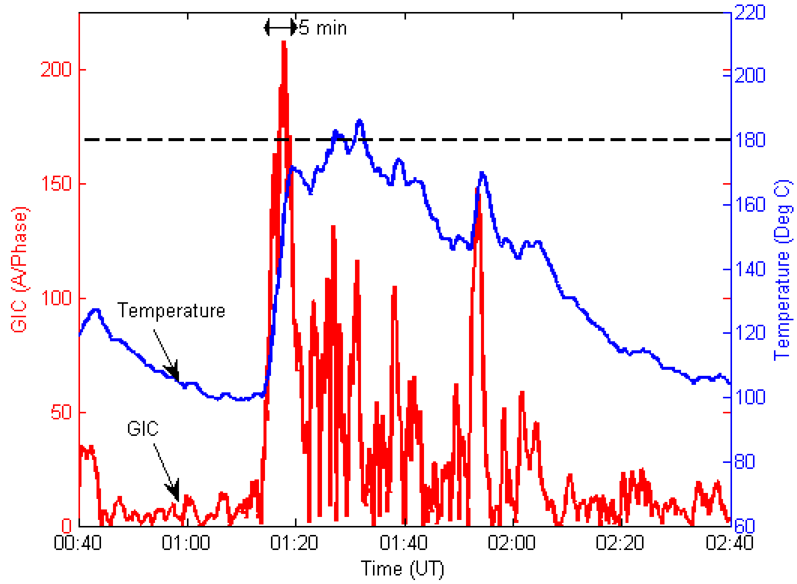

Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

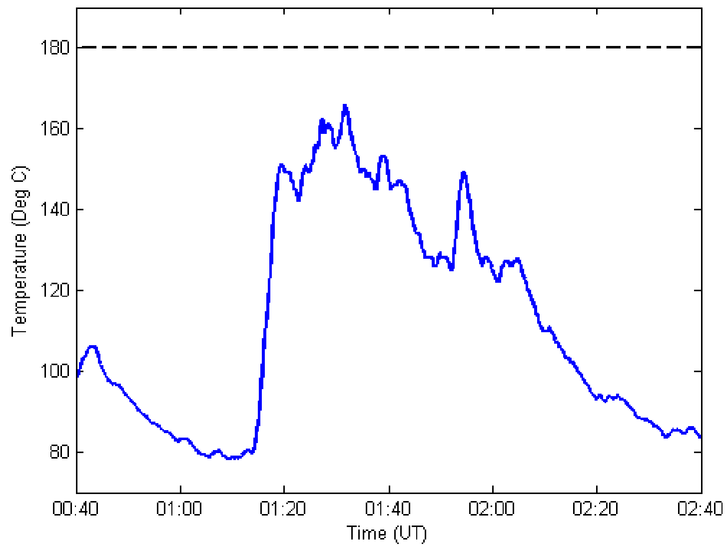

Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 13** (calculated using formulas from IEEE Std C57.91).

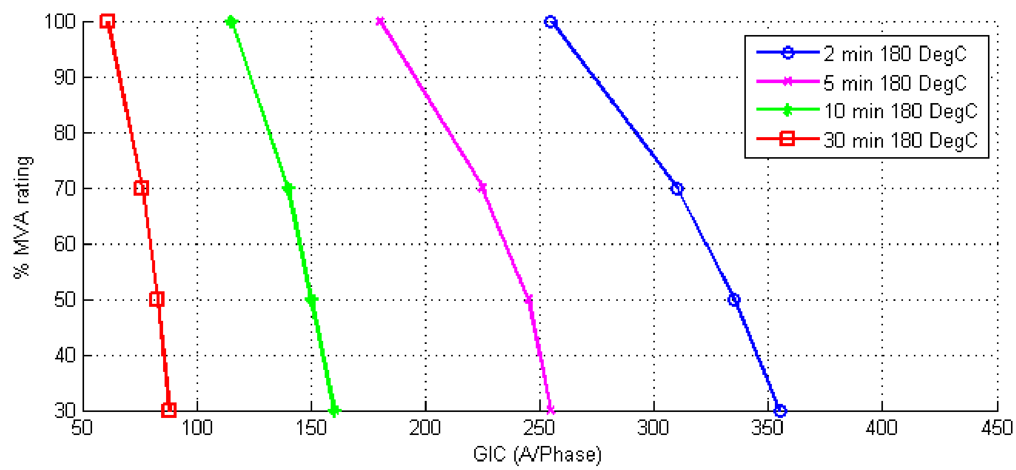

Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

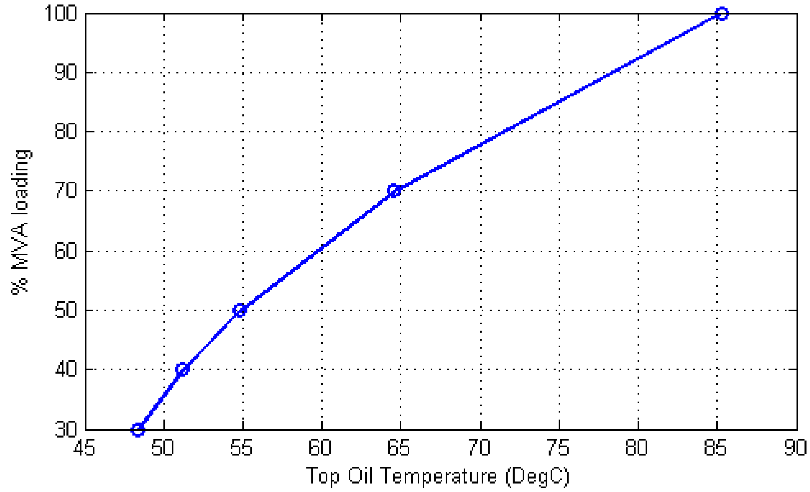

Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

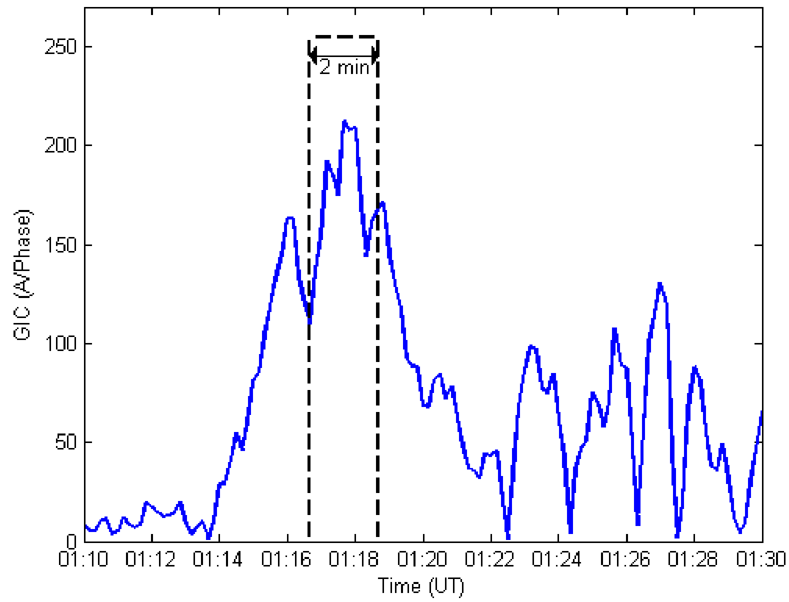

Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

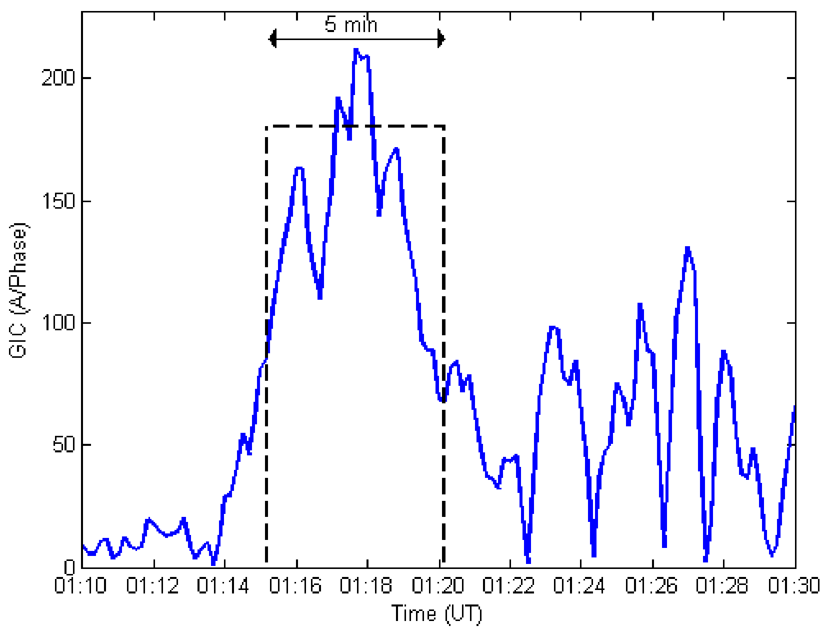

Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

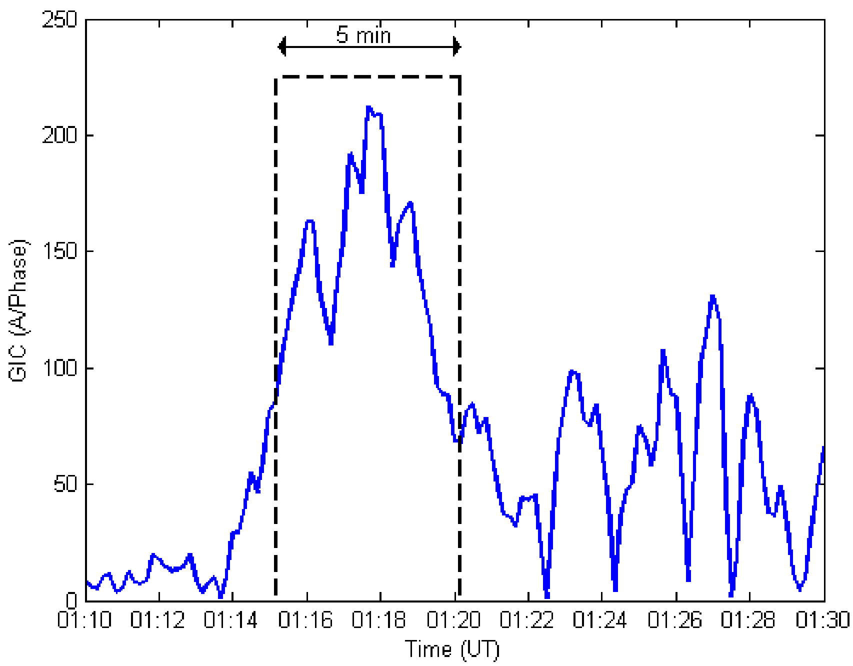

Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (2)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (3)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (4)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**.

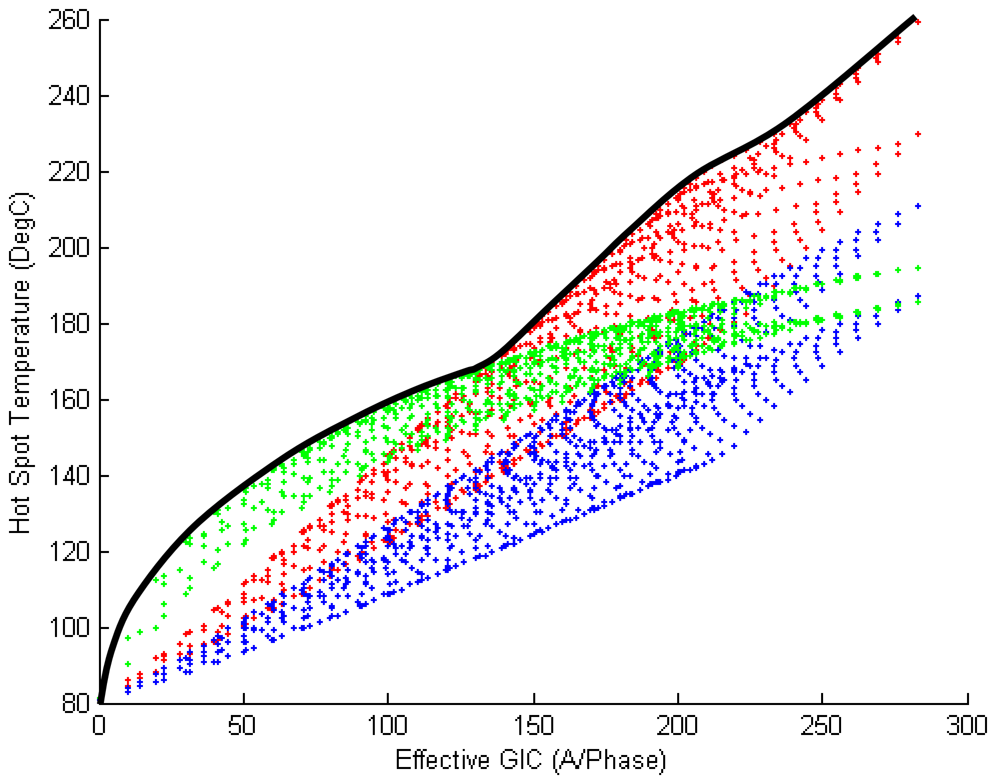

Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 104°C and 150°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 150°C falls well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
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Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 150°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the condition of specific transformers where IEEE Std C57.91-2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the screening model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- The 75 A per phase screening threshold was determined on the basis of instantaneous peak hot spot temperatures. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.
- The models used in the determination of the threshold are conservative but technically justified.

- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

Appendix

The screening thermal model is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 2**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 3 and 4**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The third transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 5 and 6**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

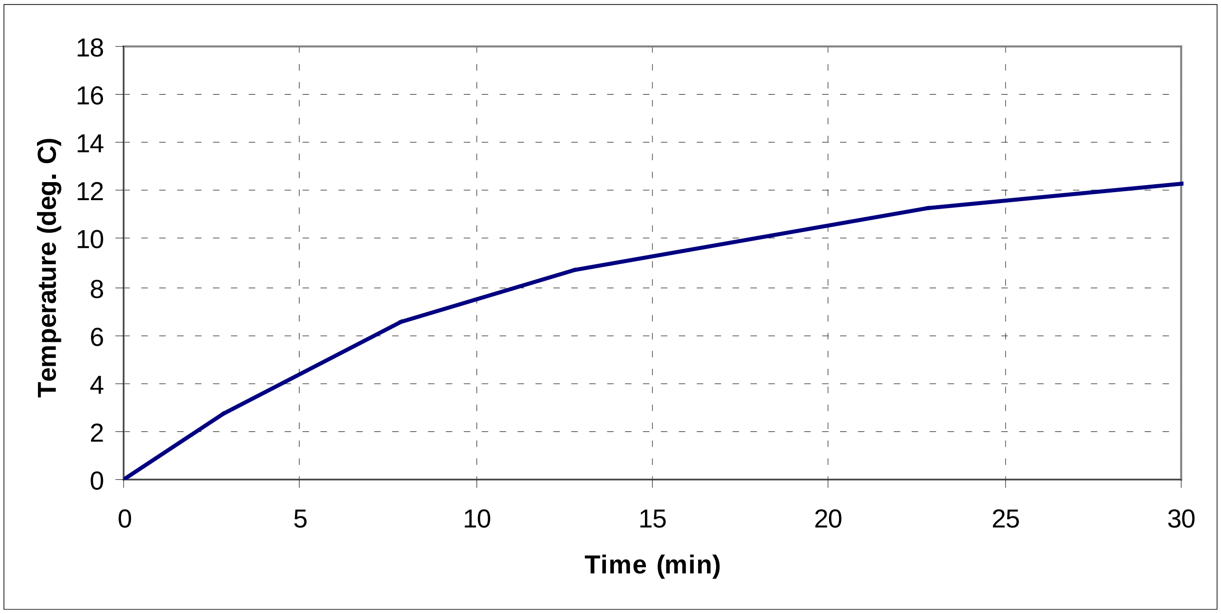

Figure 2: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

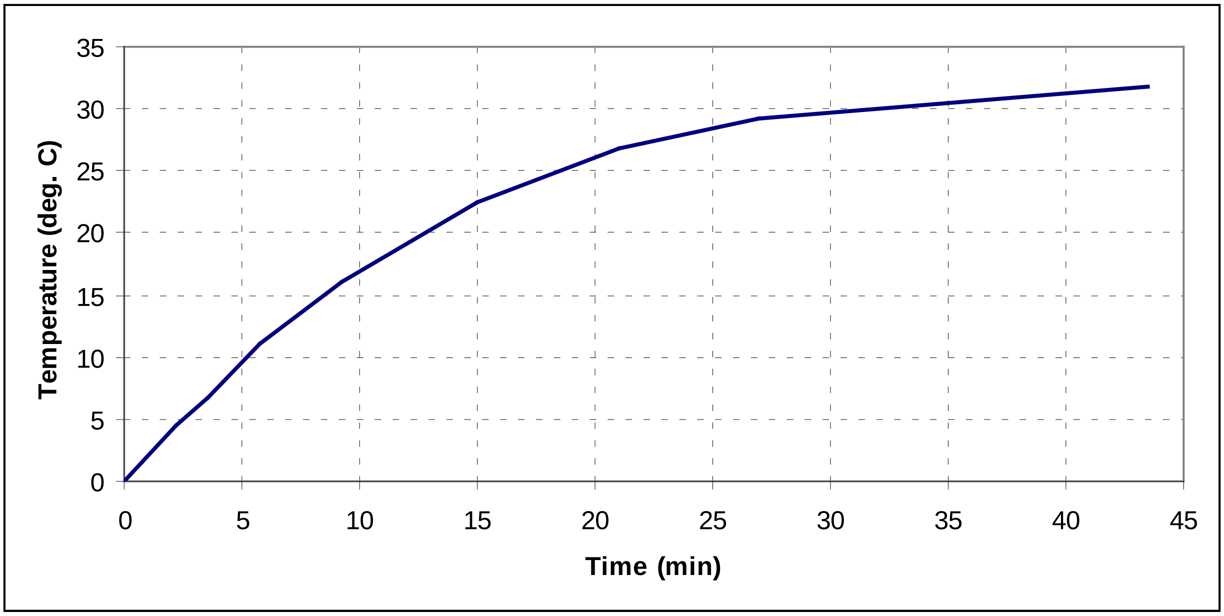

Figure 3: Step thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 10 A per phase dc step.

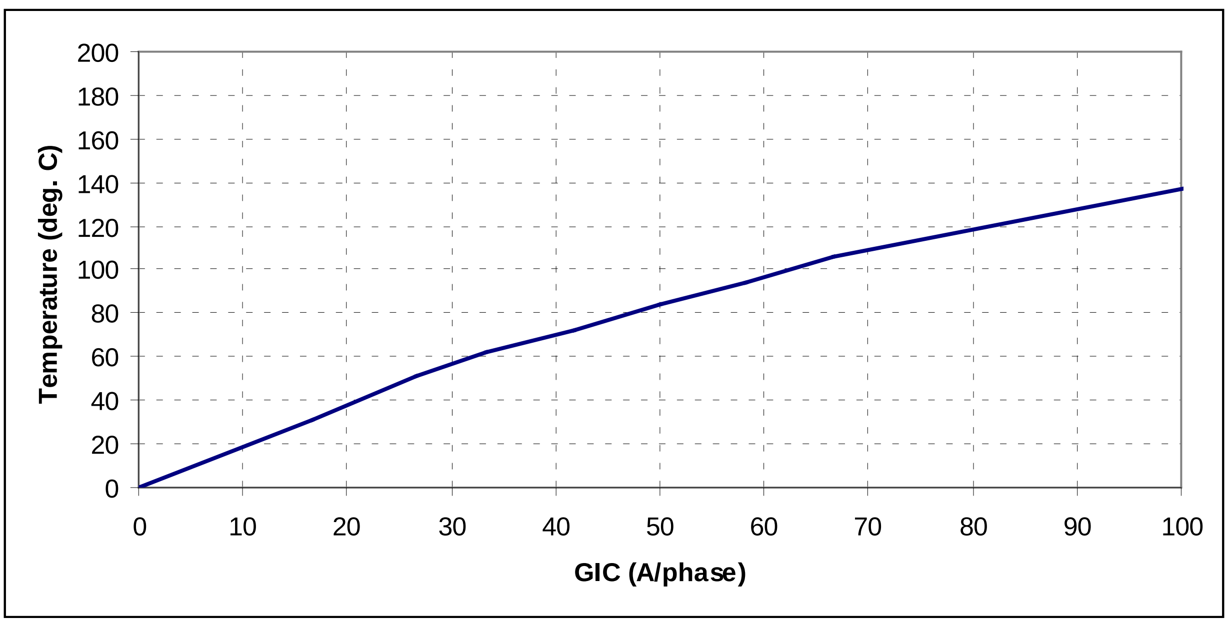

Figure 4: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

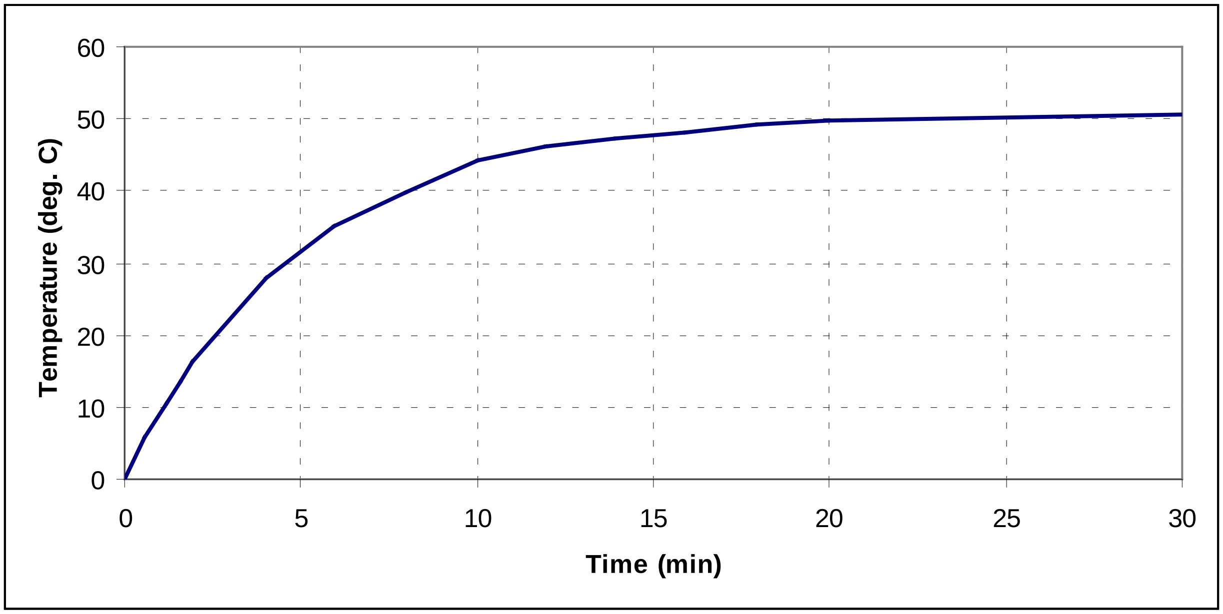

Figure 5: Step thermal response of tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

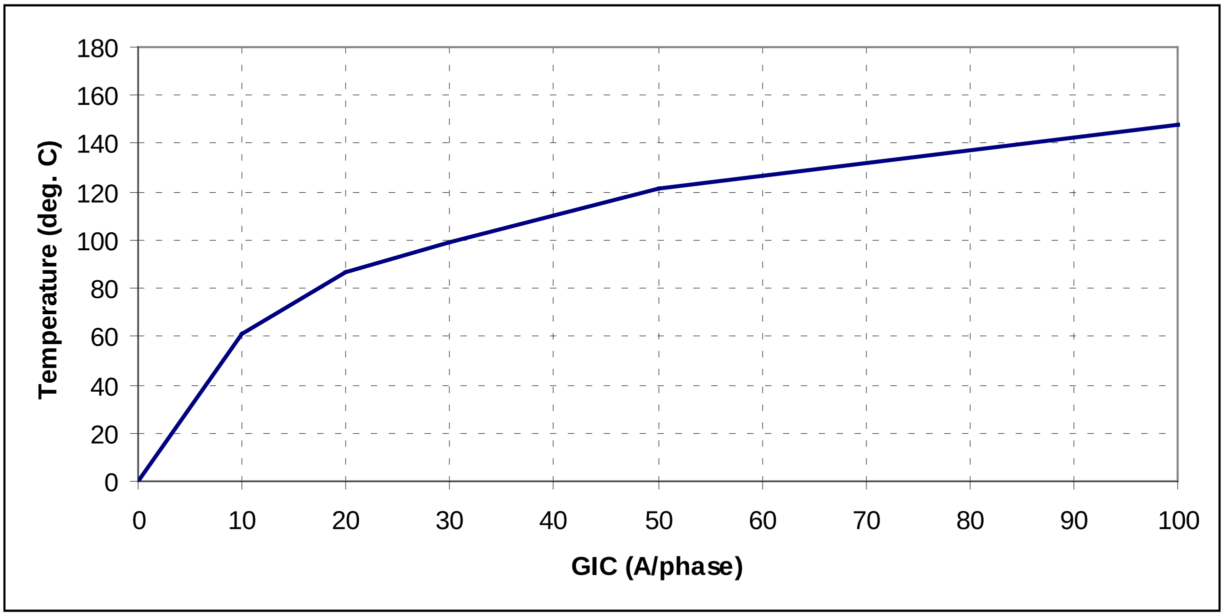

Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The composite envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event			
Effective GIC (A/phase)	**Metallic hot spot Temperature (°C)**	**Effective GIC(A/phase)**	**Metallic hot spot Temperature (°C)**
0	80	140	172
10	106	150	180
20	116	160	187
30	125	170	194
40	132	180	200
50	138	190	208
60	143	200	214
70	147	210	221
75	150	220	224
80	152	230	228
90	156	240	233
100	159	250	239
110	163	260	245
120	165	270	251
130	168	280	257

For instance, if effective GIC is 150 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 180°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 59°C at maximum ambient temperature, then 210 A per phase of effective GIC translates in a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of GIC_E and GIC_N that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same screening model. For instance, the lower bound of peak temperatures for the screening model for 210 A per phase is 165°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

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Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

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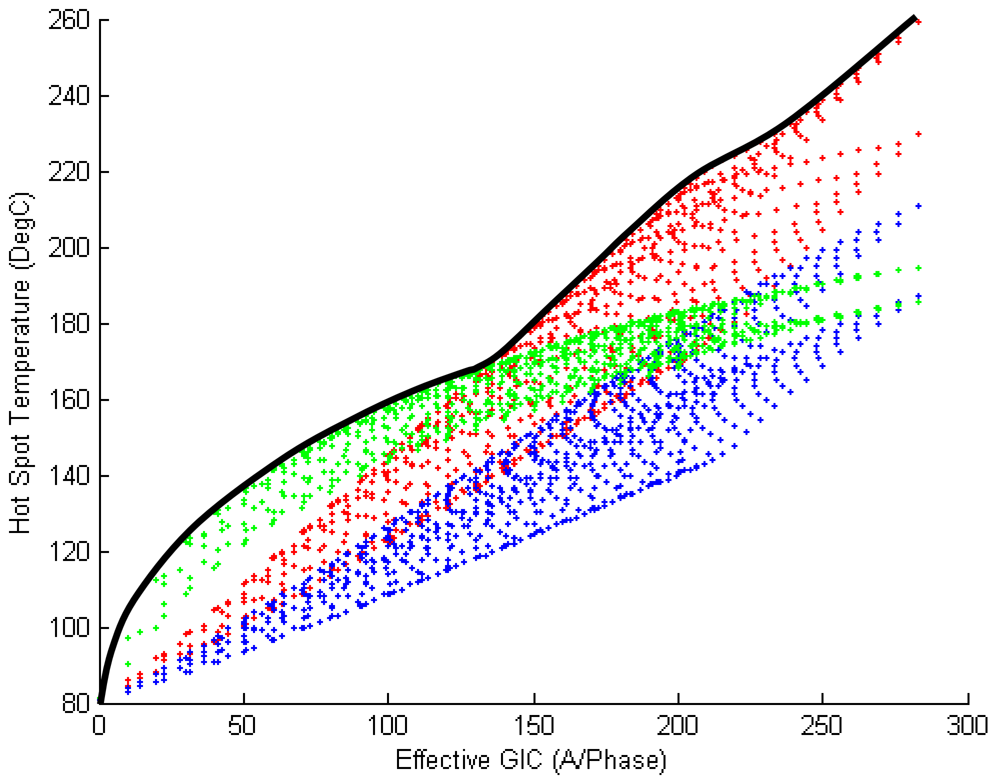

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Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 104°C and 150°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 150°C falls well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

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The selection of the 75 A per phase screening threshold is based on the following considerations:

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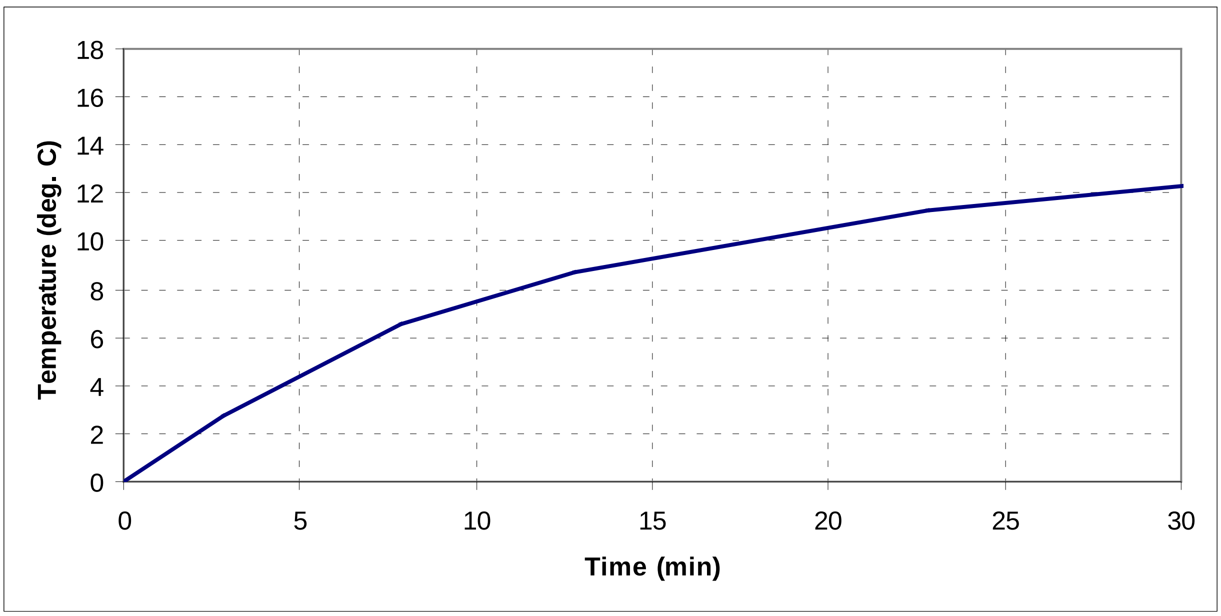

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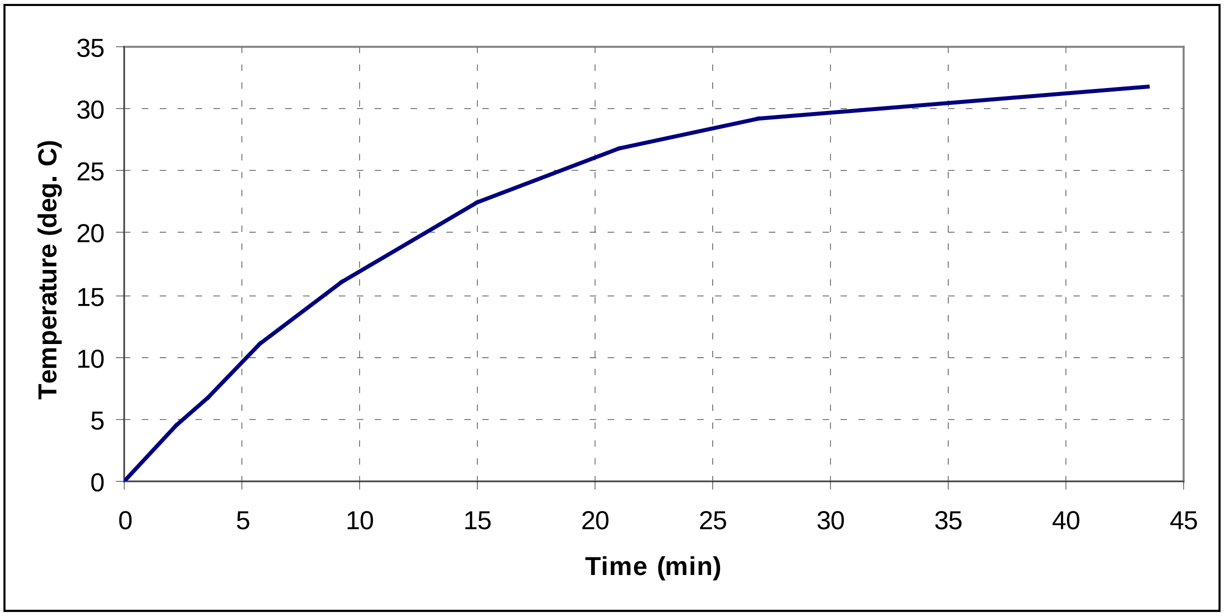

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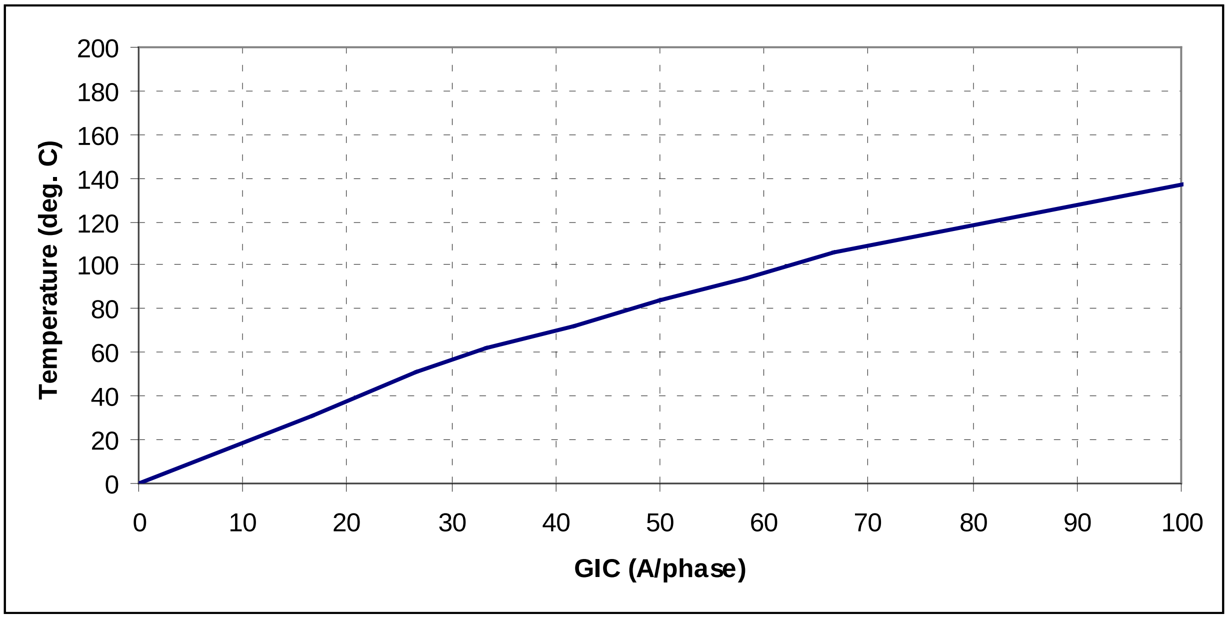

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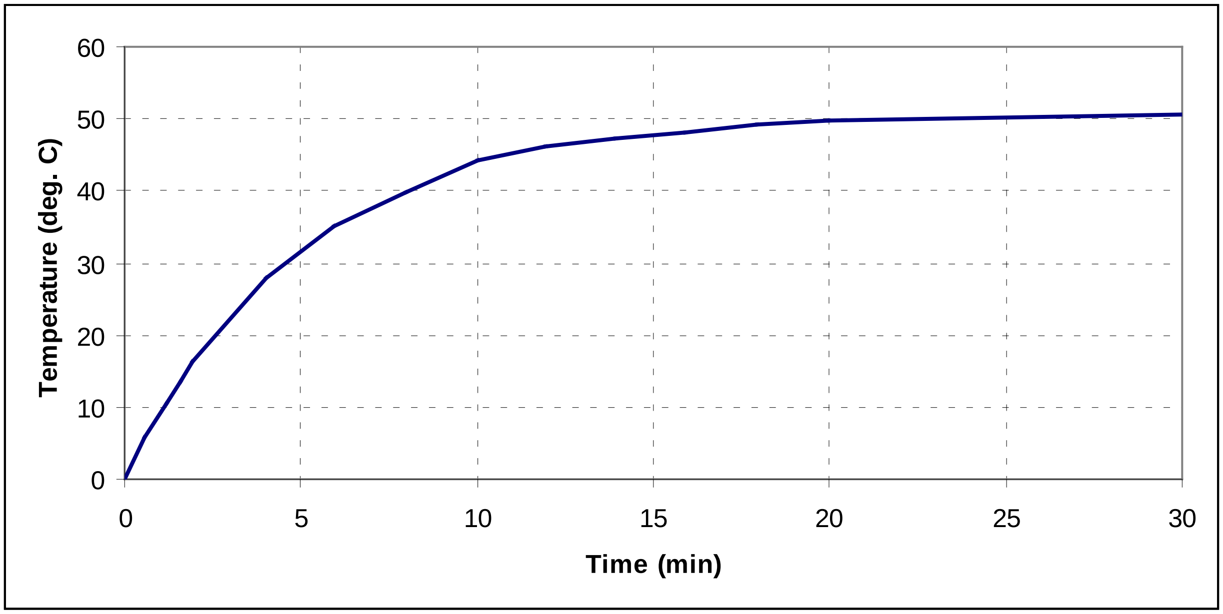

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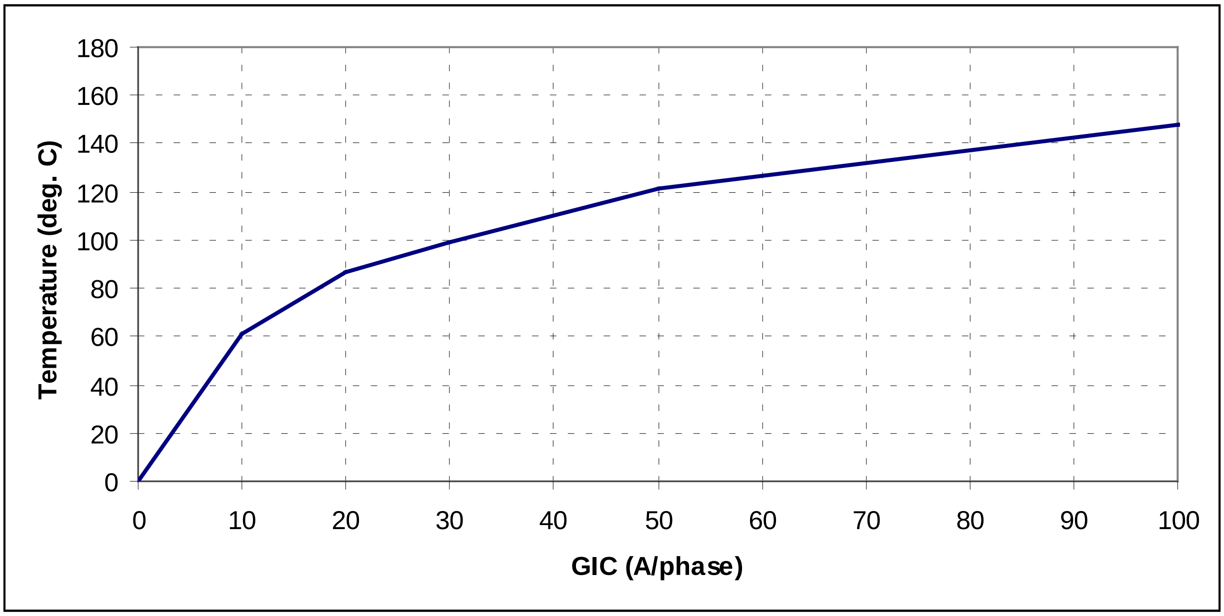

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Violation Risk Factor and Violation Severity Level Justifications

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities

- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs corresponding to requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-violation per-day basis is the “default” for penalty calculations.

VRF Justifications – TPL-007-1, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Lower is consistent with approved TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-1 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Lower is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing GMD studies, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System under conditions of a GMD event.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its

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

VSL Justifications – TPL-007-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R7. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with the VRF for approved TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-1, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the GMD Vulnerability Assessment. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R2			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R2			
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to models for GMD Vulnerability Assessments. Approved TPL-001-4 Requirement R1 requires entities to maintain System models for Planning Assessments and has multiple subparts to form the basis for a graduated VRF. However, the System model for GMD Vulnerability Assessment will have most elements in common with the System model used for Planning Assessments in TPL-001-4. System models for GMD Vulnerability Assessment are distinguished primarily in that they account for reactive power losses due to GIC. Therefore, the subparts from approved TPL-001-4 Requirement R1 were not duplicated in proposed TPL-007-1 Requirement R2 and the VSL was not separated into further degrees of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R2	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-1 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during a benchmark GMD event; these criteria may be different from the voltage limits determined in approved TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-1, R3			
			System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.

VSL Justifications – TPL-007-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R5. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-1, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the BES meets performance criteria. Proposed TPL-007-1 Requirement R3 requires responsible entities to complete a GMD Vulnerability Assessment to ensure the system meets performance criteria during a benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in

Proposed VSLs – TPL-007-1, R4			
months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

VSL Justifications – TPL-007-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R4	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A VRF of Medium is also consistent with approved IRO-010-1a Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-1 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R5			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R5			
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved MOD-032-1, Requirement R2 and IRO-010-1a, Requirement R3, which also have a graduated scale for VSLs.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R5	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-1 Requirement R6 requires responsible entities to conduct a thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly	The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of	The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or	The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely

Proposed VSLs – TPL-007-1, R6			
owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in	three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in	owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.

Proposed VSLs – TPL-007-1, R6			
	Requirement R6, Parts 6.1 through 6.3.	Requirement R6, Parts 6.1 through 6.3.	

VSL Justifications – TPL-007-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved FAC-008-3, Requirement R6. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications – TPL-007-1, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-1 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While approved TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-1 has split the requirements for performing a GMD Vulnerability Assessment and development of the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of ~~v~~Violation ~~r~~Risk ~~f~~Factors (VRFs) and ~~v~~Violation ~~s~~Severity ~~l~~Levels (VSLs) for each requirement in TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The ~~Standard Drafting Team~~SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, 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. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that ~~Violation Risk Factor~~VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement ~~Violation Risk Factor~~VRF assignments and the main Requirement ~~Violation Risk Factor~~VRF assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of ~~Violation Risk Factor~~VRFs corresponding to ~~R~~requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular ~~Violation Risk Factor~~VRF level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such ~~R~~requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

~~Violation Severity Level~~VSLs ~~(VSLs)~~ define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

~~Violation severity level~~VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

~~. . . u~~Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per-~~-~~violation per-~~-~~day basis is the "default" for penalty calculations.

VRF Justifications – TPL-007-1, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of Lower is consistent with approved TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-1 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A ~~Violation Risk Factor~~VRF of Lower is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models and performing GMD studies, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System under conditions of a GMD event.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-1, R1			
Lower	**Moderate**	**High**	**Severe**

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

VSL Justifications – TPL-007-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R7. That requirement also has a binary, Severe VSL.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of High is consistent with the VRF for approved TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-1, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete GMD Vulnerability Assessment(s).
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the GMD Vulnerability Assessment. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R2			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R2			
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete GMD Vulnerability Assessment(s).

VSL Justifications – TPL-007-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to models for GMD Vulnerability Assessments. Approved TPL-001-4 Requirement R1 requires entities to maintain System models for Planning Assessments and has multiple subparts to form the basis for a graduated VRF. However, the System model for GMD Vulnerability Assessment will have most elements in common with the System model used for Planning Assessments in TPL-001-4. System models for GMD Vulnerability Assessment are distinguished primarily in that they account for reactive power losses due to GIC. Therefore, the subparts from approved TPL-001-4 Requirement R1 were not duplicated in proposed TPL-007-1 Requirement R2 and the VSL was not separated into further degrees of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R2	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of Medium is consistent with approved TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-1 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during a benchmark GMD event; these criteria may be different from the voltage limits determined in approved TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-1, R3			
			System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.

VSL Justifications – TPL-007-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R5. That requirement also has a binary, Severe VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-1, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the BES meets performance criteria. Proposed TPL-007-1 Requirement R3 requires responsible entities to complete a GMD Vulnerability Assessment to ensure the system meets performance criteria during a benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in

Proposed VSLs – TPL-007-1, R4			
less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.

VSL Justifications – TPL-007-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.

VSL Justifications – TPL-007-1, R4	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of Medium is consistent with approved MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A ~~Violation Risk Factor~~VRF of Medium is also consistent with approved IRO-010-1a Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-1 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R5			
Lower	**Moderate**	**High**	**Severe**

Proposed VSLs – TPL-007-1, R5			
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved MOD-032-1, Requirement R2 and IRO-010-1a, Requirement R3, which also have a graduated scale for VSLs.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R5	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of Medium is consistent with approved FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-1 Requirement R6 requires responsible entities to conduct a thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a transformer thermal impact assessment could directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a thermal impact assessment for 5% or less or one	The responsible entity failed to conduct a thermal impact assessment for more than 5% up	The responsible entity failed to conduct a thermal impact assessment for more than 10%	The responsible entity failed to conduct a thermal impact assessment for more than 15%

Proposed VSLs – TPL-007-1, R6			
of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required	up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required	or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in

Proposed VSLs – TPL-007-1, R6			
	elements as listed in Requirement R6, Parts 6.1 through 6.3.	elements as listed in Requirement R6, Parts 6.1 through 6.3.	Requirement R6, Parts 6.1 through 6.3.

VSL Justifications – TPL-007-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved FAC-008-3, Requirement R6. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-1, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-1, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A ~~Violation Risk Factor~~VRF of High is consistent with approved TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-1 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While approved TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-1 has split the requirements for performing a GMD Vulnerability Assessment and development of the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, ~~parts~~ Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, ~~parts~~ Parts 7.1 through 7.3.	The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, ~~parts~~ Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Three VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard. However, the requirement is similar to approved TPL-001-4, Requirement R2. That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-1, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Stage 2

Order No. 779 Citation	Directive/Guidance	Resolution
P 2	Within 18 months of the effective date of this final rule, NERC must submit for approval one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.	The proposed standard requires applicable Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners to conduct periodic assessments of the impacts of a 100-year benchmark GMD event on their systems.
P 2	The Second Stage GMD Reliability Standard must identify what severity GMD events (i.e. benchmark GMD events) that responsible entities will have to assess for potential impacts on the Bulk-Power System.	The benchmark GMD event is described in the drafting team's white paper available on the project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx The benchmark provides a defined event for assessing system performance as required by the proposed standard. It defines the geoelectric field values used to compute geomagnetically-induced current flows for a GMD Vulnerability Assessment.
P 28	We expect that NERC and industry will consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stage GMD Reliability Standards.	The directive was met in the development of the proposed standard. The SDT chose a planning standard approach to meet the directives for the second stage GMD reliability standards, which allows responsible entities latitude to select mitigation from a variety of considerations which may include cost. Like other planning standards, TPL-007-1 does not prescribe specific mitigation measures or strategies. When mitigation is necessary to meet the performance requirements specified in the standard, responsible entities can evaluate options using criteria which can include cost considerations. Comments on mitigation costs were solicited from stakeholders during formal comments and considered by the SDT.

Order No. 779 Citation	Directive/Guidance	Resolution
P 51	The Commission accepts the proposal in NERC's May 21, 2012 post-Technical Conference comments and directs NERC to "identify facilities most at-risk from severe geomagnetic disturbance" and "conduct wide-area geomagnetic disturbance vulnerability assessment" as well as give special attention to those Bulk-Power System facilities that provide service to critical and priority loads. As noted...owners and operators of the Bulk-Power System will perform the assessments.	When fully implemented, the proposed standard will enable wide-area assessment of GMD impact by owners and operators. Through the standard development process, industry has provided projections on the time required for obtaining validated tools, models, and data necessary for conducting GMD Vulnerability Assessments. The five-year phased Implementation Plan has been tailored accordingly and reflects a realistic timeline for expecting owners and operators to perform GMD Vulnerability Assessments. Corrective Action Plans required by the proposed standard provide the means to address risk to all facilities from a benchmark GMD event, not only those determined to be most at-risk in wide-area assessments. The proposed standard enhances NERC's ability to further assess the reliability risks that geomagnetic disturbances pose to the Bulk-Power System through the reliability assessment functions described in Section 800 of the NERC Rules of Procedure. During the five-year implementation period, NERC will closely support industry preparations, monitor implementation, and assess progress and initial results. Once the proposed standard is fully implemented, NERC and the Regional Entities will be better able to further assess the potential impacts of GMD events on the Bulk-Power System as a whole and update the 2012 Interim Report.
P 67	Each responsible entity under the Second Stage GMD Reliability Standards would then be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR [P 28 - 32] and adopted in this Final Rule.	The proposed standard requires applicable entities to perform assessments that will identify the impacts from benchmark GMD events on the interconnected transmission system. • Evaluation criteria are uniformly established in Requirement R4, Table 1, and Attachment 1.

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	• First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments... • Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers[1], including the effects of GICs originating from and passing to other regions. • Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues • Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed... • Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.	o Requirement R4 specifies system conditions. o Table 1 establishes uniform performance criteria. o Attachment 1 describes the procedure for calculating the benchmark GMD event for use in the GMD Vulnerability Assessment. • Requirements R4 and R6 address assessments of the effects of GIC on applicable transformers. o Requirement R4 specifies that responsible planning entities must conduct GMD Vulnerability Assessments that include steady state analysis to ensure transformer reactive losses from a benchmark GMD event do not produce voltage collapse, Cascading, and uncontrolled islanding. o Requirement R6 specifies that Transmission Owners and Generator Owners must conduct thermal impact assessments of applicable power transformers. • Requirements R4 and Table 1 address assessments of the effects of GIC on other Bulk-Power System equipment. Table 1 specifies that Reactive Power compensation devices and other Transmission Facilities are removed in the GMD study as a result of Protection System operation or Misoperation due to harmonics. Thus the GMD Vulnerability Assessment includes the system effects caused by GIC impacts on other BPS equipment. • The proposed standard accounts for wide-area impacts by requiring information exchange and involving appropriate applicable entities. Requirement R4 and Requirement R7 specify that GMD Vulnerability Assessments and Corrective Action Plans must be provided to Reliability Coordinators, adjacent planning entities, and functional entities

[1] The NOPR described damage to Bulk-Power System components as a primary effect of GICs and production of harmonics that are not present during normal Bulk-Power System operation and increased transformer absorption of reactive power as secondary effects of GICs. NOPR, 141 FERC ¶ 61,045 at P 13.

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		specifically referenced in the plans. Reliability Coordinators work together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function. Planning Coordinators integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. • The proposed standard requires GMD Vulnerability Assessments to be periodically updated, not to exceed every 60 calendar months.
P 67	The NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate assessments across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness.	Planning Coordinators are included as applicable entities in the proposed standard to integrate plans within their areas and coordinate plans with adjacent Planning Coordinators as described in the NERC Functional Model. Requirement R1 in the proposed standard requires the Planning Coordinator to "identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s)". Requirement R4 specifies that GMD Vulnerability Assessments are provided to adjacent Planning Coordinators. Requirement R7 specifies that Corrective Action Plans are provided to adjacent Planning Coordinators. These requirements provide the necessary information exchange for planning activities. In addition, the proposed standard designates Reliability Coordinators as a recipient of GMD Vulnerability Assessments and Corrective Action Plans. Reliability Coordinators work

Order No. 779 Citation	Directive/Guidance	Resolution
		together to maintain Real-time reliable operations in the Wide Area. The information in GMD Vulnerability Assessments and Corrective Action Plans from entities in the Reliability Coordinator Area will support this function.
P 68	NERC should consider developing Reliability Standards that can incorporate improvements in the scientific understanding of GMDs. When developing the Second Stage GMD Reliability Standards implementation schedule, NERC should consider the availability of validated tools, models, and data necessary to comply with the Requirements.	The requirements in the proposed standard are performance-based which allow applicable entities to use state of the art tools and methods to accomplish the specified reliability objectives. The standard does not contain prescriptive requirements for entities to use specific tools, models, or procedures which would limit the applicability of improvements in scientific understanding. Furthermore the use of modern magnetometer data and statistical methods in determining the benchmark GMD event supports reevaluation as additional magnetometer data is collected during future solar cycles. The 5-year phased implementation period was developed with consideration for the availability of validated tools, models, and data required by applicable entities.
P 79	If the assessments identify potential impacts from benchmark GMD events, owners and operators must develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event. • Owners and operators of the Bulk-Power System cannot limit their plans to considering operational procedures or enhanced training alone, but must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the benchmark GMD events	The directive is met by requiring an entity to develop a Corrective Action Plan in the event its system fails to meet specified performance criteria. Requirement 7, Part 7.1 lists acceptable actions which are not limited to considering Operating Procedures or enhanced training.

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	based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.	
P 82	As with the First Stage GMD Reliability Standards, the responsible entities should perform vulnerability assessments of their own systems and develop the plans for mitigating any identified vulnerabilities. We take no position in this Final Rule on which functional entities should be responsible for compliance under the Second Stage GMD Reliability Standards. However, the NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate mitigation plans across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness. We clarify that if a responsible entity performs the required GMD vulnerability assessments and finds no potential GMD impacts, no plan is required under the Second Stage GMD Reliability Standards.	The proposed standard requires applicable entities to conduct assessments on their systems and develop plans to mitigate identified vulnerabilities. In Requirement R1, Planning Coordinators and Transmission Planners identify responsibilities for maintaining models and performing studies needed for GMD Vulnerability Assessments specified in Requirement R4. In Requirement R6, Transmission Owners and Generator Owners are required to conduct thermal impact assessments of applicable BES power transformers and, if necessary, specify mitigating actions. Requirement R7 specifies that the applicable planning entity must develop a Corrective Action Plan in the event that it concludes through the GMD Vulnerability Assessment that the system does not meet performance requirements. An entity that performs a GMD Vulnerability Assessment and does not identify a deficiency in system performance is not required to develop a Corrective Action Plan.
P 84	The Second Stage GMD Reliability Standards should not impose “strict liability” on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity.	The proposed standard is a planning standard where the benchmark GMD event is the planning basis. The standard does not impose strict liability on failure to ensure reliable operation during a GMD event of unforeseen severity.
P 85	Given that some responsible entities have or may choose automatic blocking measures, the NERC standards development process should consider how to verify that selected blocking measures are effective and consistent with the reliable operation of the Bulk-Power System.	The GMD Vulnerability Assessment process considers all mitigation measures in modeling, assessment, and mitigation requirements. Requirement R2 specifies that responsible entities shall maintain system models for performing GMD Vulnerability

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		Assessments, which will include automatic blocking measures that are part of the system as described in the technical guidance. The responsible entity must perform studies based on these models as required in Requirement R4 to verify effectiveness and the reliable operation of the system. When a responsible entity identifies a need for mitigation actions such as blocking measures, Requirement R6 and R7 specify that information must be shared with planning entities to ensure that the mitigation actions are consistent with reliable operation.
P 86	While responsible entities will decide how to mitigate GMD vulnerabilities on their systems, the NERC standards development process should consider how the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic measures including, for example, some combination of blocking, improved "withstand" capability, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.	The directive is met in Requirement R7. Responsible entities that conclude through the GMD Vulnerability Assessment that their System does not meet performance requirements are required to develop a Corrective Action Plan. The plan must list deficiencies and the associated actions needed to achieve required performance. Requirement R7 provides examples of such actions: installation or modification of equipment, use of Operating Procedures, and other actions specified in the requirement.
P 91	NERC must propose an implementation plan.	The implementation plan was developed through the standards development process.
P 91	We do not direct or suggest a specific implementation plan. As stated in the NOPR, in a proposed implementation plan, we expect that NERC will consider a multi-phased approach that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable operation of the Bulk-Power System are protected first. We also expect, as discussed above, that the implementation plan will take into account the availability of validated tools, models, and data that are necessary for	Compliance with the proposed standard is to be implemented over a 5-year period as described in the Implementation Plan. Phased implementation provides • Necessary time for entities to obtain tools, models, and data required for GMD vulnerability assessments • Proper sequencing of system and equipment assessments performed by various applicable functional entities to build an overall assessment of GMD vulnerability.

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	responsible entities to perform the required GMD vulnerability assessments.	• Adequate time for development of viable Corrective Action Plans that detail actions and timelines necessary to achieve required performance. Development of Corrective Action Plans may require entities to develop, perform, and or validate new and/or modified studies, assessments, procedures, etc. to meet the TPL-007-1 requirements.

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation

Final Ballot Now Open through December 16, 2014

Now Available

A final ballot for **TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events** is open through **8 p.m. Eastern, Tuesday, December 16, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

The voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson, Standards Developer at 404-446-9760.

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1

Final Ballot Results

Now Available

A final ballot for **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** concluded **8 p.m. Eastern on Tuesday, December 16, 2014**.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Quorum /Approval
84.27% / 78.05%

Background information for this project can be found on the project page.

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Mark Olson, or by telephone at 404-446-9760.

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Ballot Results	
Ballot Name:	Project 2013-03 GMD TPL-007-1_Final_Ballot_December_2014
Ballot Period:	12/5/2014 - 12/16/2014
Ballot Type:	Final
Total # Votes:	316
Total Ballot Pool:	375
Quorum:	**84.27 % The Quorum has been reached**
Weighted Segment Vote:	78.05 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	107	1	67	0.788	18	0.212	0	4	18
2 - Segment 2	8	0.6	5	0.5	1	0.1	0	1	1
3 - Segment 3	86	1	48	0.762	15	0.238	0	6	17
4 - Segment 4	24	1	15	0.833	3	0.167	0	2	4
5 - Segment 5	79	1	49	0.803	12	0.197	0	6	12
6 - Segment 6	54	1	35	0.778	10	0.222	0	5	4
7 - Segment 7	3	0.2	2	0.2	0	0	0	0	1
8 - Segment 8	5	0.5	2	0.2	3	0.3	0	0	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.6	5	0.5	1	0.1	0	0	1
Totals	**375**	**7**	**229**	**5.464**	**63**	**1.536**	**0**	**24**	**59**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	William Temple	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker		
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Eric Olson	Affirmative	

1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	California ISO	Rich Vine	Negative	COMMENT RECEIVED
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	American Public Power Association	Nathan Mitchell		
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN		
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Negative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	

3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Negative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Affirmative	

5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	COMMENT RECEIVED
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Southern Indiana Gas and Electric Co.	Rob Collins	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Calpine Energy Services	Agus Bintoro		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	

6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Exhibit J

Standard Drafting Team Roster for Project 2013-03, Geomagnetic Disturbance Mitigation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2013-03 Geomagnetic Disturbance Mitigation

Name and Title	Company and Address	Contact Info	Bio
Frank Koza, P.E. Chair Executive Director of Infrastructure Planning	PJM Interconnection 955 Jefferson Avenue, Norristown, PA 19403	610.666.4228 frank.koza@ pjm.com	Executive Director of Infrastructure Planning and in charge of the technical staff associated with generator interconnection and implementation of transmission enhancements. Vice Chair of GMD Task Force. At PJM over 12 years, previously in charge of system operations. Former Chair of the NERC Operating Reliability Subcommittee and Reliability Assessments Subcommittee. Before PJM, worked for 29 years at Exelon/PECO Energy in a variety of assignments including construction of fossil and nuclear generation facilities, construction and maintenance of transmission, system planning, and system operations. MS Engineering
Randy Horton, Ph.D., P.E. Vice Chair Chief Engineer, Transmission	Southern Company Services 42 Inverness Pkwy Birmingham, AL 35242	205.257.6352 jrhorton@ southernco.com	Chief Engineer of Southern Company Services Transmission Technical Support. Leader of GMD Task Force GIC Model Development team. Held

Name and Title	Company and Address	Contact Info	Bio
Technical Support			various engineering positions within the Protective Equipment Applications (system protection) and Technical Studies groups of Alabama Power Company and Southern Company Services, progressing to Principal Engineer before joining EPRI in 2010. While at EPRI, he progressed to Senior Project Manager and was lead researcher in the NERC and DOE sponsored GMD project which included the development of software tools and methods used to analyze the impacts of a severe GMD on the bulk electric system. Developed and published a geomagnetically induced current (GIC) benchmark model that has been used by commercial software vendors and others to develop and validate GIC models. Senior Member of the IEEE and Member of CIGRE. Chair of the IEEE Working Group on Field Measured Overvoltages, Co-Chair of the IEEE GMD Task Force, Advisory Council Member for EPRI's

Name and Title	Company and Address	Contact Info	Bio
			Substations Research Program.
Donald Atkinson, P.E. Relay and Control Designer and System Protection Engineer	Georgia Transmission Corporation 2100 East Exchange Pl Tucker, GA 30085	770.270.7178 donald.atkinson@ gatrans.com	Relay and Control Designer and System Protection engineer. Responsible for relay designs, calculating relay settings, conducting system planning studies, event analyses, creating relay standards, and writing transmission substation operating instructions. BS in Electrical Engineering (power systems).
Emanuel Bernabeu, Ph.D., P.E. Lead Power Engineer, Special System Studies	Dominion Technical Solutions, Inc 2400 Grayland Ave Richmond, VA 23220	804-257-4017 emanuel.e. bernabeu@ dom.com	Lead power engineer for special system studies at Dominion. Member of the GMD Task Force Equipment Modeling team. Responsible for Dominion's GMD risk assessment and mitigation strategy with extensive experience regarding modeling, planning, situational awareness, and operational procedures for GMD. Experience with GIC system calculations, voltage stability analysis, equipment vulnerability, and mitigation planning. Senior engineer for projects in transient over-voltages (TOV), EMI, "Aurora" cyber/physical attack, N-1-1 contingency

Name and Title	Company and Address	Contact Info	Bio
			analysis, black-start stability assessment, Phasor Measurements Units (PMUs) applications, and root cause analysis of protection relay misoperations. Member of NERC's Severe Impact Resilience Task Force (SIRTF).
Kenneth Fleischer, P.E. Nuclear Chief Electrical / I&C Engineer	NextEra Energy P.O. Box 14000 Juno Beach, FL 33408	561.691.2456 kenneth.fleischer@fpl.com	Nuclear Chief Electrical Engineer responsible for Electrical/I&C activities for five Nuclear Power Generating Stations. Experience with solar mitigation activities during Solar Cycle 23 while employed at another nuclear power complex in New Jersey that had developed mitigation procedures from the 1989 solar events that damaged several generator step up transformers. Joined NextEra/FPL in 2005, and took the solar mitigation experience and applied it to the northern nuclear sites in order to protect their generator step up transformers from extreme solar geomagnetic disturbance events. This included equipment, transformer GIC thermal rating calculations/studies, and

Name and Title	Company and Address	Contact Info	Bio
			detailed GMD mitigation procedures.
Luis Marti, Ph.D., PEng Director, Reliability Studies, Strategies, and Compliance	Hydro One Networks 483 Bay St Toronto M5G 2P5	416.345.5317 luis.marti@ HydroOne.com	Director of Reliability Studies, Strategies, and Compliance, including Special Studies, Hydro One. Leader of GMD Task Force Equipment Modeling Team. Research/study activities include the development of models for the family of EMTP programs, GIC simulation, grounding, induction coordination, EMF issues pertaining to T&D networks, and connection/operational issues around the connection of renewable generation in distribution networks. Participated in a number of Canadian and international technical organizations such as CSA (Canadian Standards Association), IEEE (Fellow 2015), and CIGRE. Adjunct professor at the universities of Waterloo, Western Ontario and Ryerson.
Antti Pulkkinen, Ph.D.	NASA Goddard Space Flight Center 8800 Greenbelt Rd Greenbelt, MD 20771	301-286-0652 antti.a.pulkkinen@nasa.gov	Director of Space Weather Research Center (SWRC) operated at NASA GSFC. Leader of GMD Task Force Space Weather Science team developing reference storm scenarios.

Name and Title	Company and Address	Contact Info	Bio
			Published 1-in-100 year storm scenarios used in the 2012 GMD Interim Report and presented at various space weather technical conferences. His research has involved studies of ground effects of space weather, complex nonlinear dynamics of the magnetosphere-ionosphere system and modeling of general space weather processes with focus on new forecasting capacity. He has led numerous space weather-related projects where scientists have been in close collaboration with industrial partners. In many of these projects, his work has involved general geomagnetic induction modeling and modeling of space weather effects on pipelines and power transmission systems.
Qun Qiu, Ph.D., P.E. Principal Engineer - Transmission Protection and Control Engineering	American Electric Power 700 Morrison Rd Gahanna, OH 43230	614.552.1182 qqiu@aep.com	Principal Engineer – Transmission Protection & Control Engineering. Member of GMD Task Force Equipment Modeling team. Leading a team in implementing company-wide GIC/Harmonics monitoring system and developing GMD

Name and Title	Company and Address	Contact Info	Bio
			mitigation efforts. Keynote presenter at February GMDTF in-person meeting, and recent speaker on GMD at CIGRE Grid of the Future Symposium, North American Transmission Forum Board Meeting, Southwest Power Pool (SPP) Compliance Forum. Co-authored several papers on GMD monitoring, GIC modeling and simulations. Chair of IEEE Power System Relaying Committee Working Group on GMD impacts to Protection Systems. Member of CIGRE; senior member of IEEE.
Mark Olson Standards Developer	NERC 3353 Peachtree Rd NE Suite 600 Atlanta, GA 30326	404.446.9760 mark.olson@nerc.net	Standards Developer at NERC since October 2012. Previously a career officer in the U.S. Navy where he served in various positions related to the operations and management of surface ships and naval personnel. Master's degree in electrical engineering from the Naval Postgraduate School and a bachelor’s degree from the U.S. Naval Academy.