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].

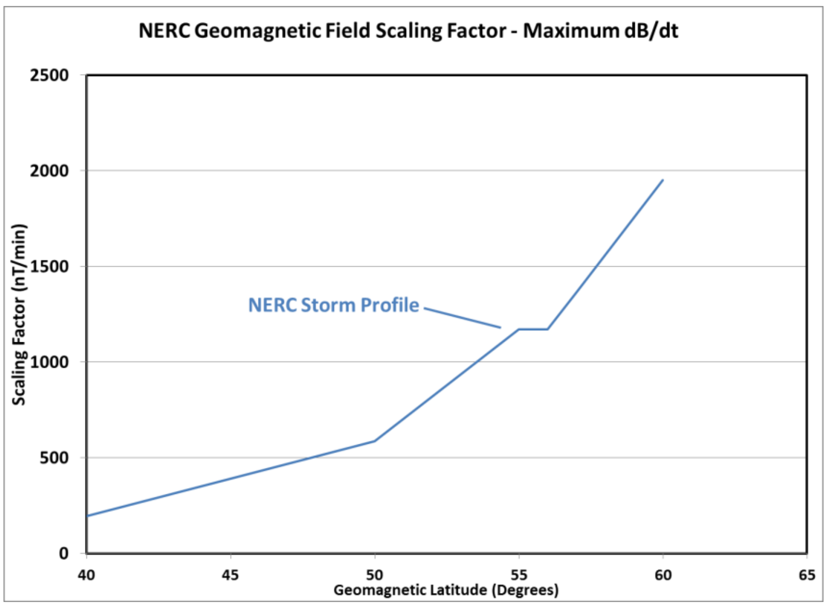

Figure 1 - NERC Proposed Profile of Geomagnetic Disturbance Intensity versus Geomagnetic Latitude

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.

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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.

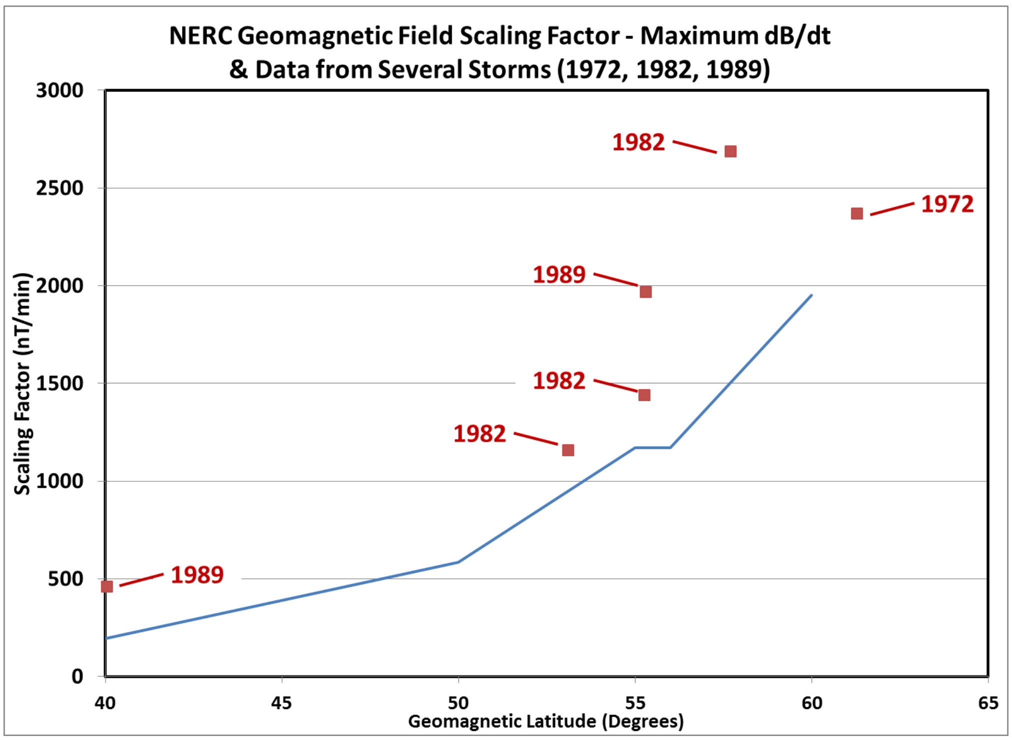

Figure 2 – NERC 100 Year Storm Reference Profile and Observations od dB/dt in 1972, 1982 and 1989 Storms that exceed the NERC Reference Profile

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^{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.

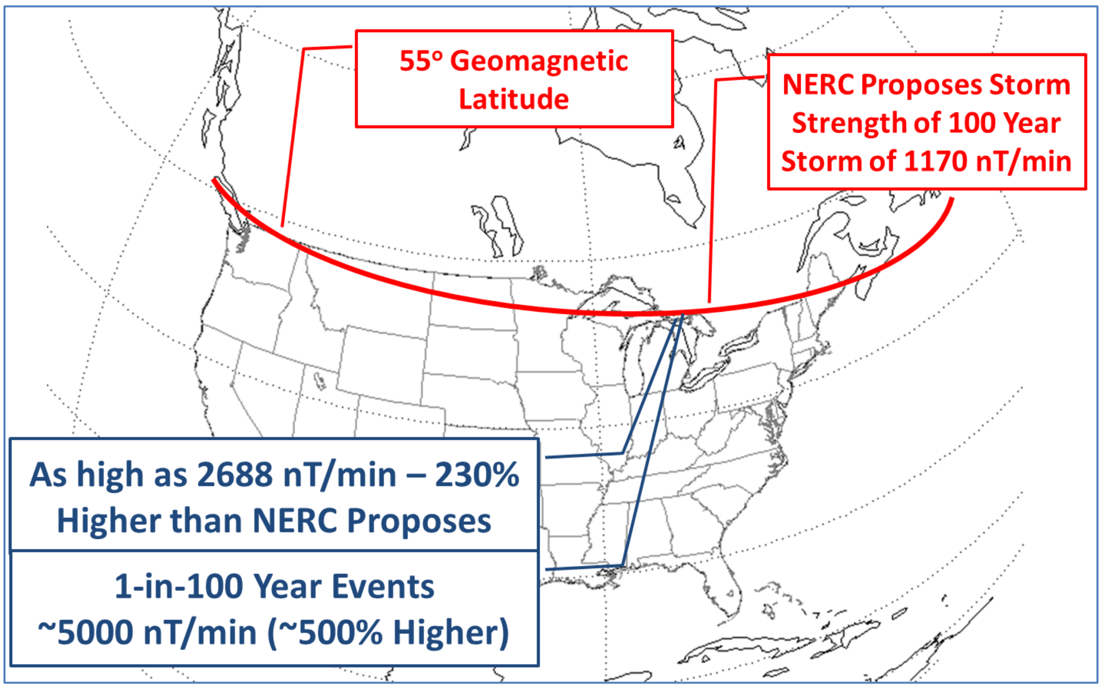

Figure 3 – Comparison of NERC Peak at 55^{o} Latitude versus Actual Observed dB/dt

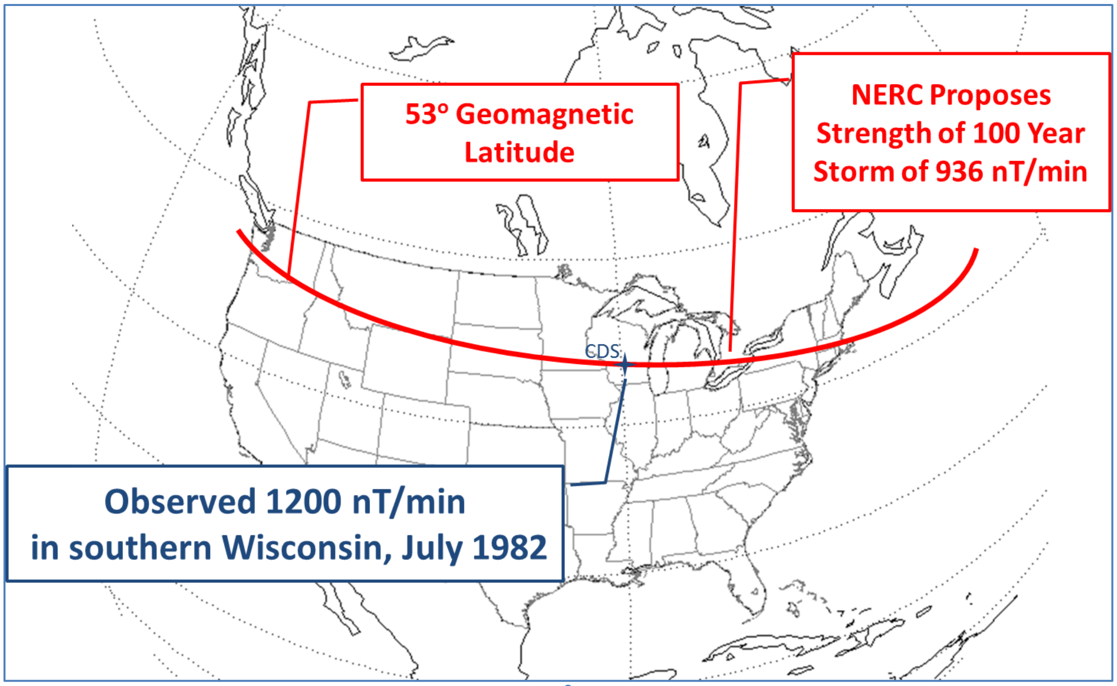

Figure 4 - Comparison of NERC Peak at 53° Latitude versus Actual Observed dB/dt

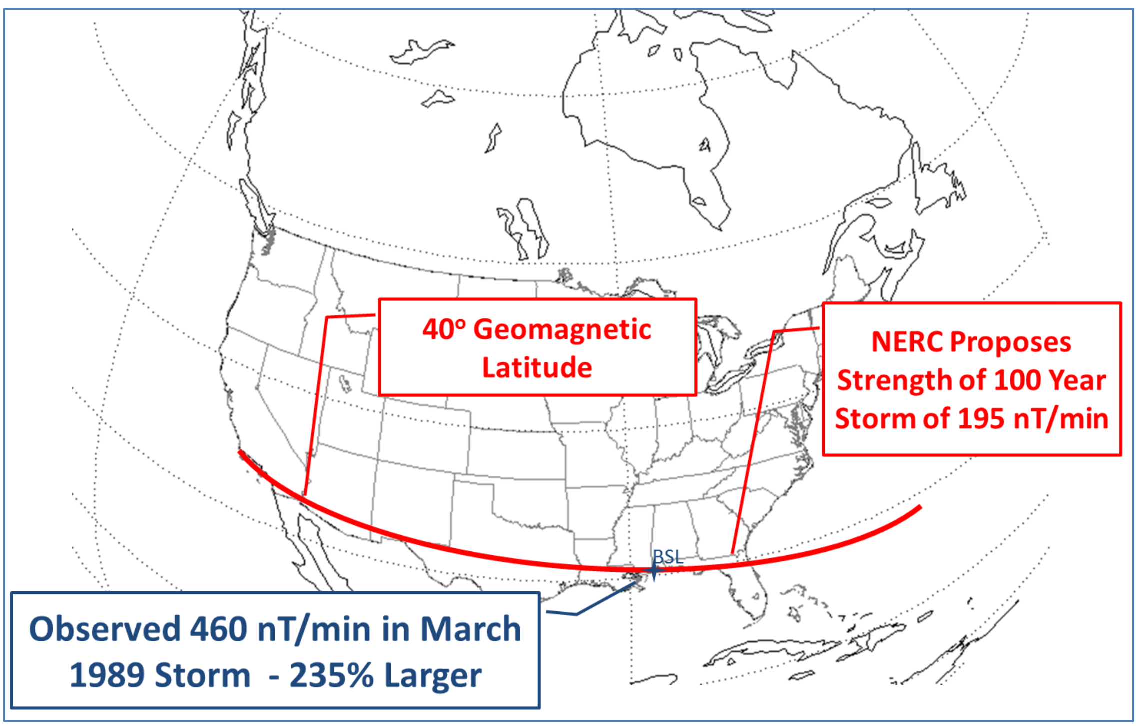

Figure 5 - Comparison of NERC Peak at 40° Latitude versus Actual Observed dB/dt

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.

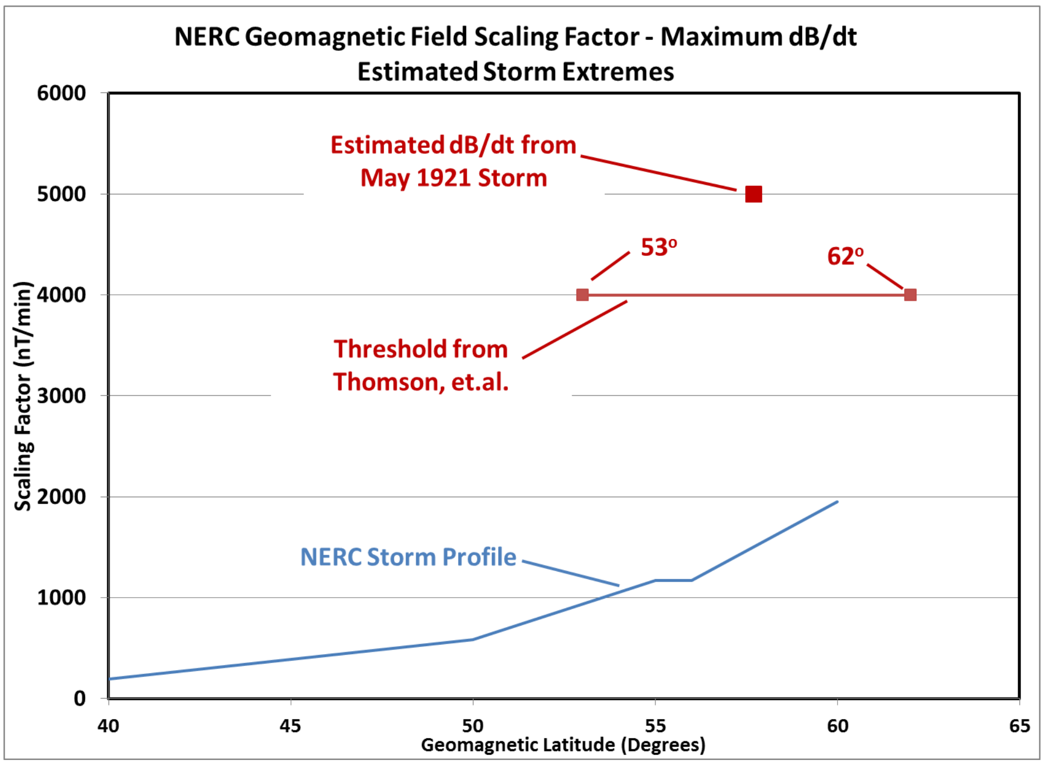

Figure 6 – Scientific Estimates of Extreme Geomagnetic Storm Thresholds compared to Propose3d NERC Draft Standard Profile

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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.

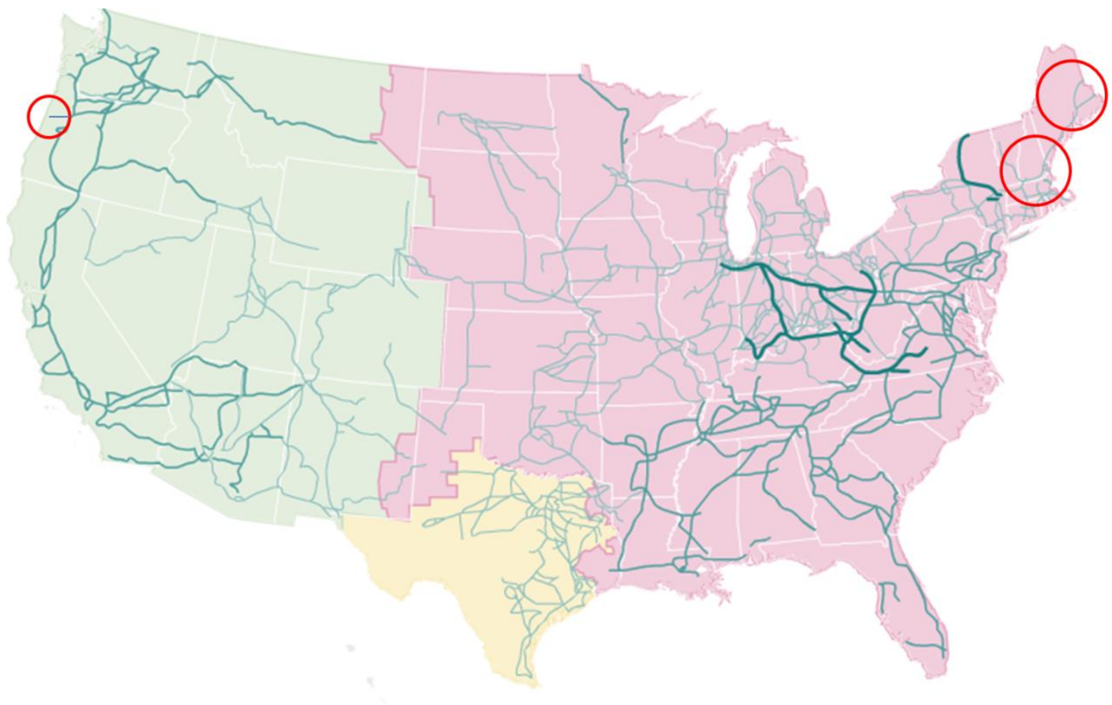


Figure 8 – Red Circles provide Region of Ground Model Validation using GIC observations from Kappenman/Radasky White Paper.

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.

[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.

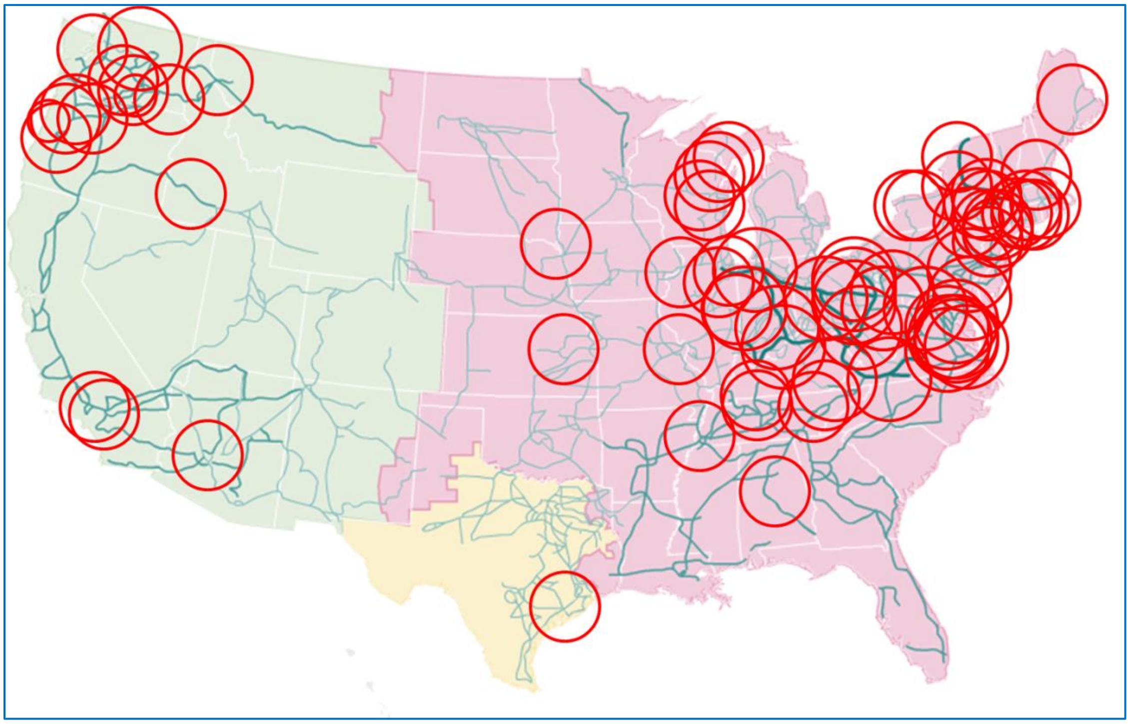


Figure 9 – GIC Observatories and US Grid-wide validation regions.

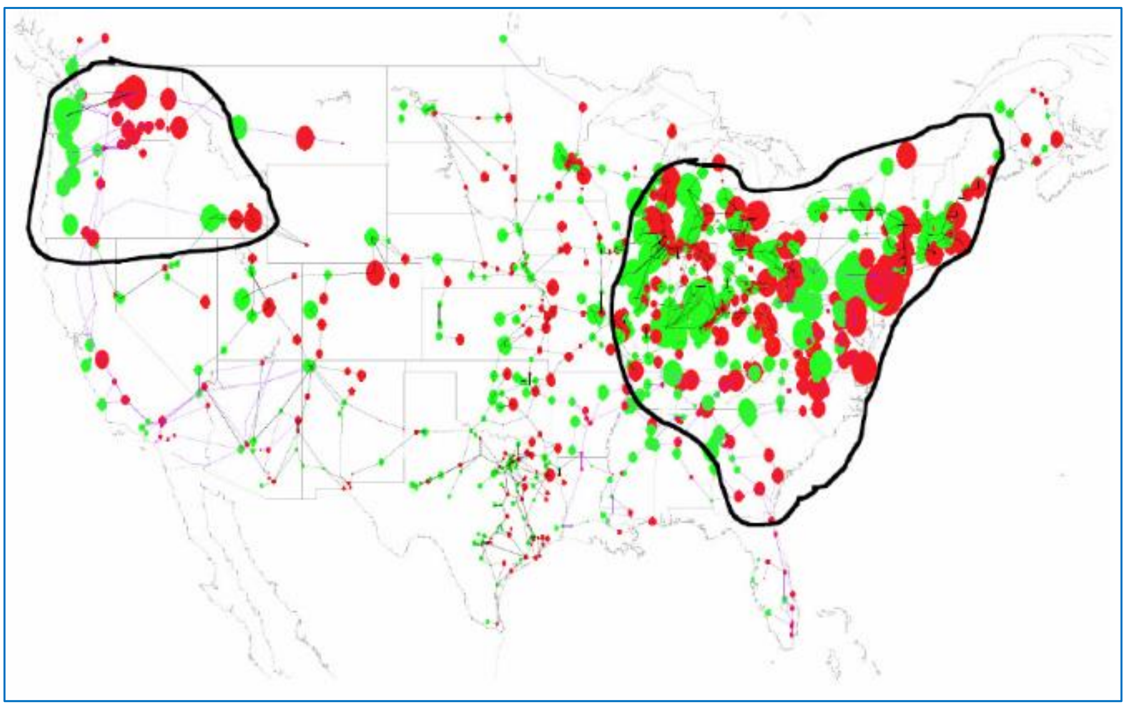


Figure 10 – Map of At-Risk Regions from Meta-R-319 Report for 50° Severe Storm Scenario

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

<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 ≥ 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.

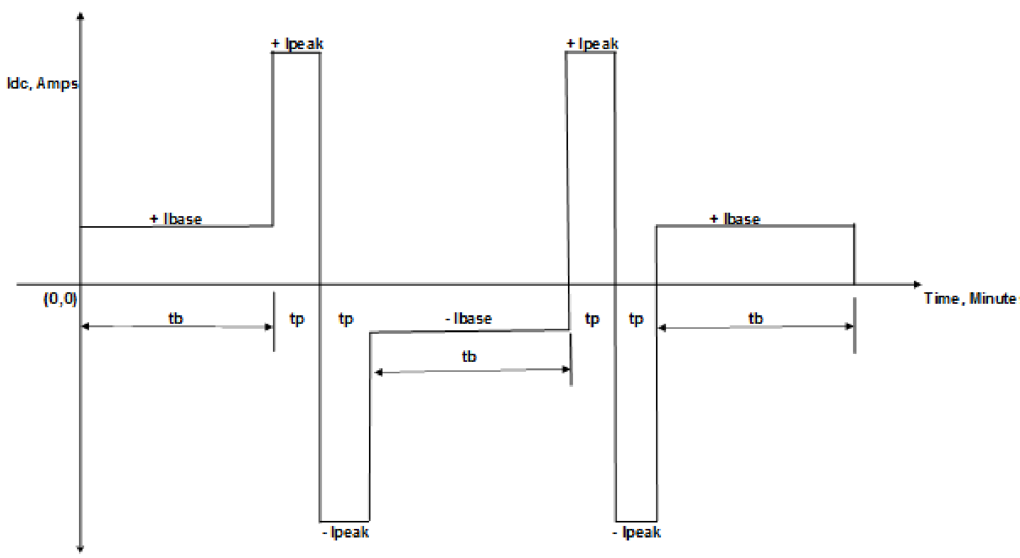
Recommendation

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
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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.

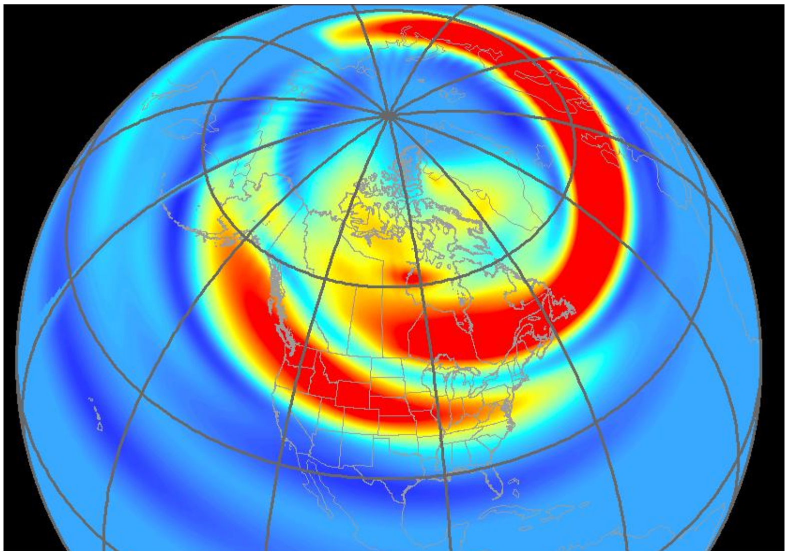

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

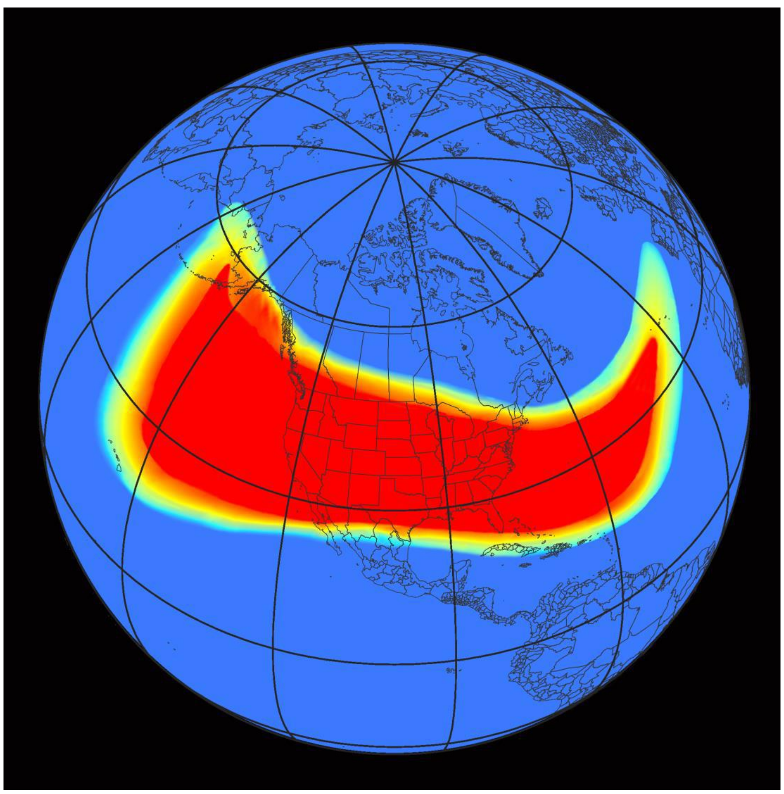

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

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

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[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]

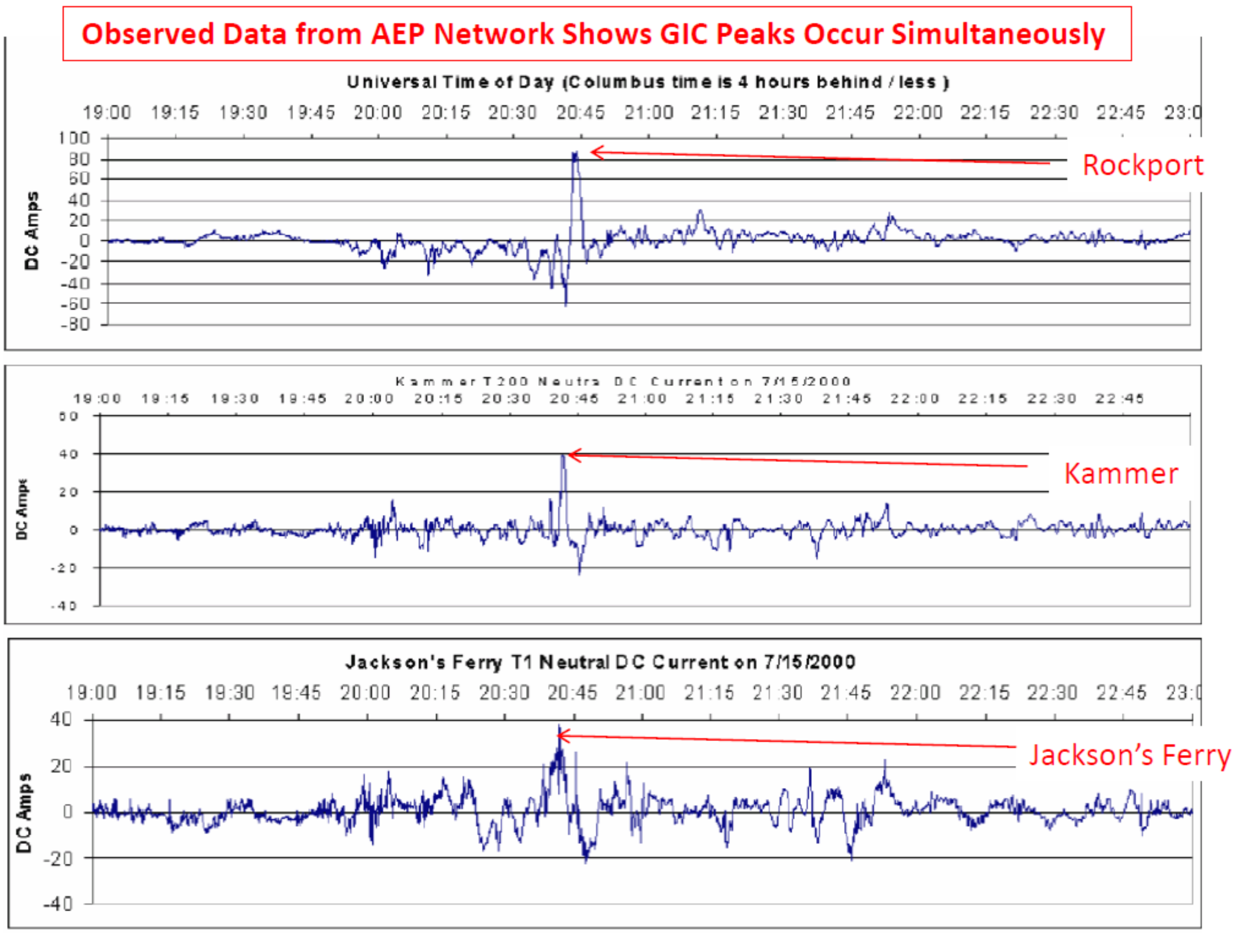
In this comment, we present data to show the NERC "hotspot" conjecture is inconsistent with real-world observations and the "Benchmark GMD Event" is therefore not scientifically well-founded.[2] Figures 1 and 2 show simultaneous GIC peaks observed at three transformers up to 580 kilometers apart, an 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.



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

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

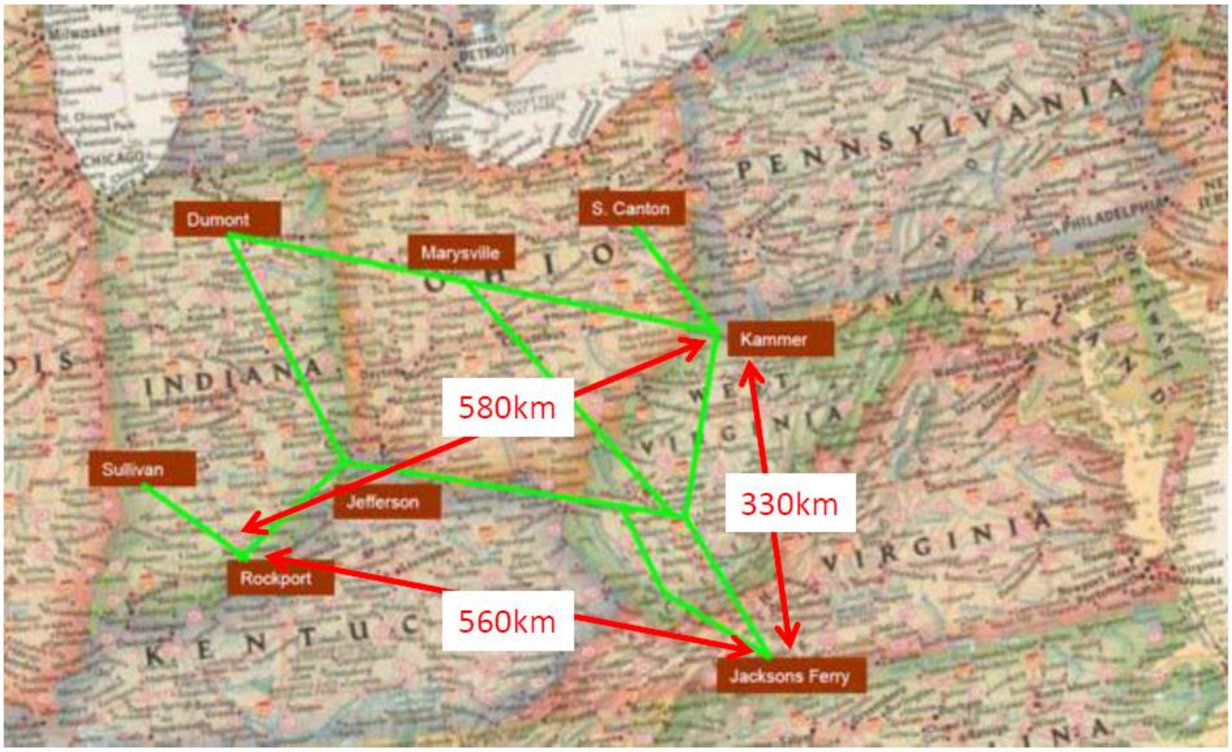


Figure 2. Location of Transformer Substations with GIC Readings on Map of States within AEP Network

Magnetometer Readings from Ottawa and St. John's Observatories During May 4, 1988 Solar Storm Show Simultaneous dB/dt Peaks Far Apart

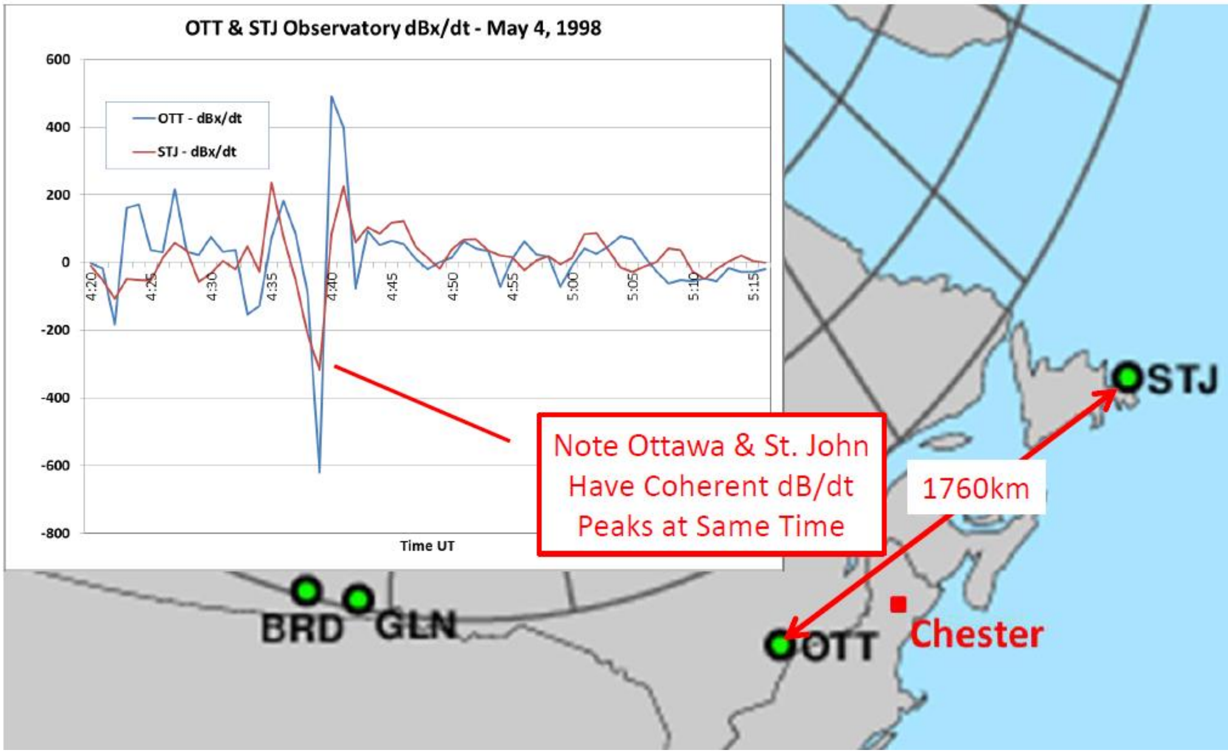


Figure 3. Magnetometer Readings Over Time from Ottawa and St. John Observatories

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.

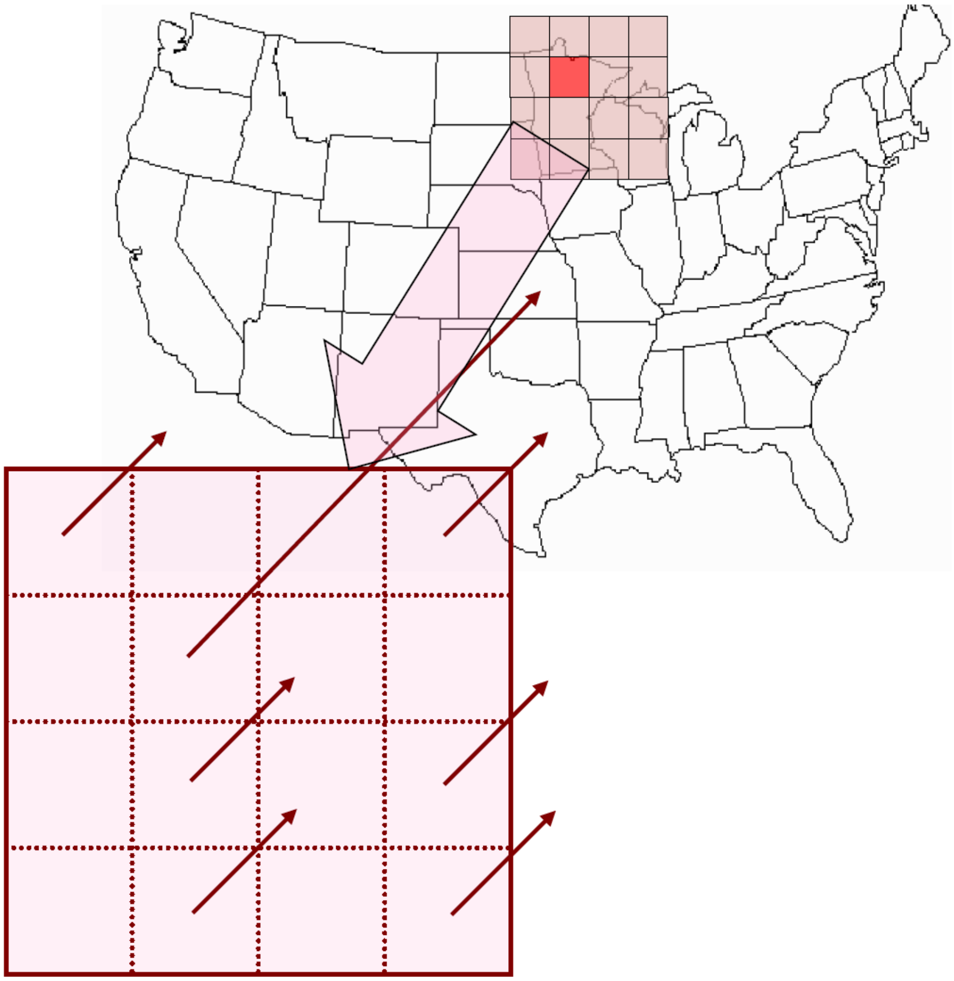


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

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.

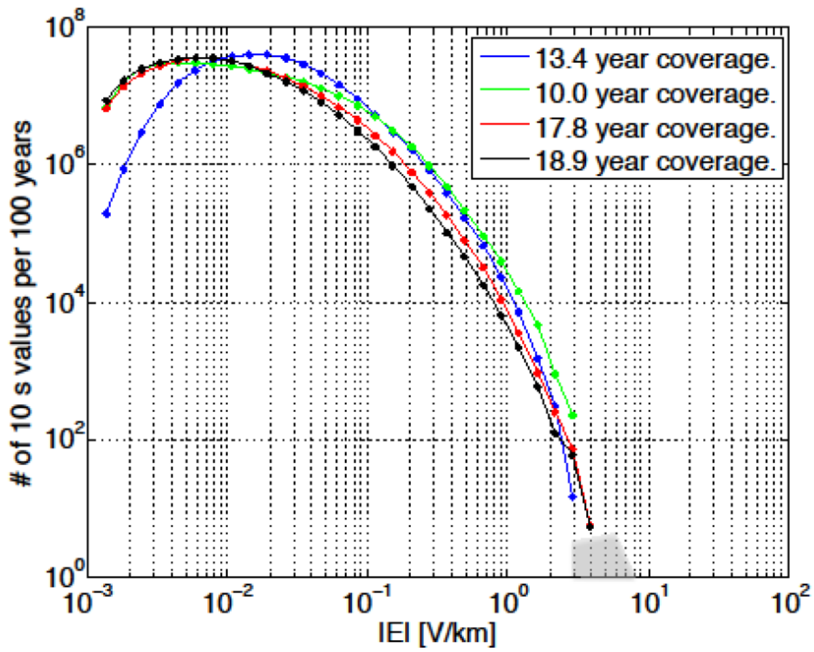


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes. Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the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

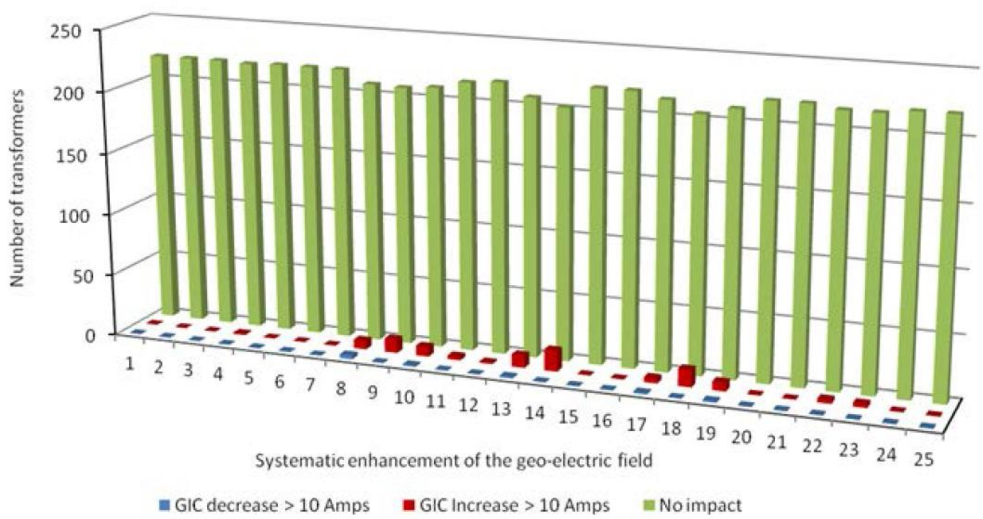


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

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.

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

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.

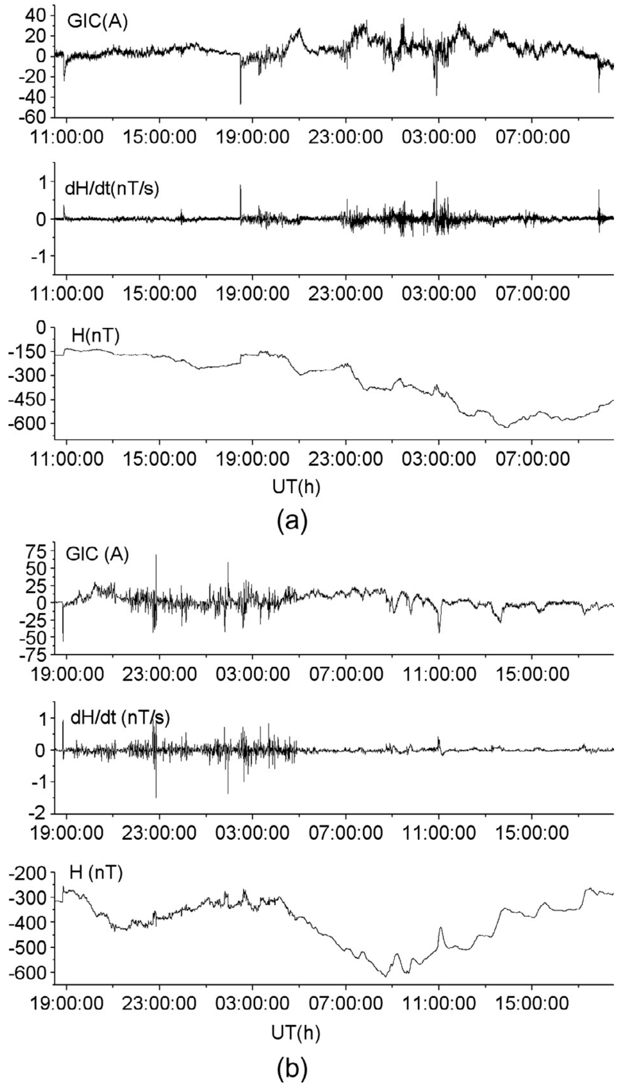


Fig. 1. GIC data at the Ling'ao nuclear power plant on 7–8 (a) and 9–10 (b) November 2004. The horizontal component of the geomagnetic field and its variation rate are also shown based on data from the Zhaoqing Geomagnetic Observatory.

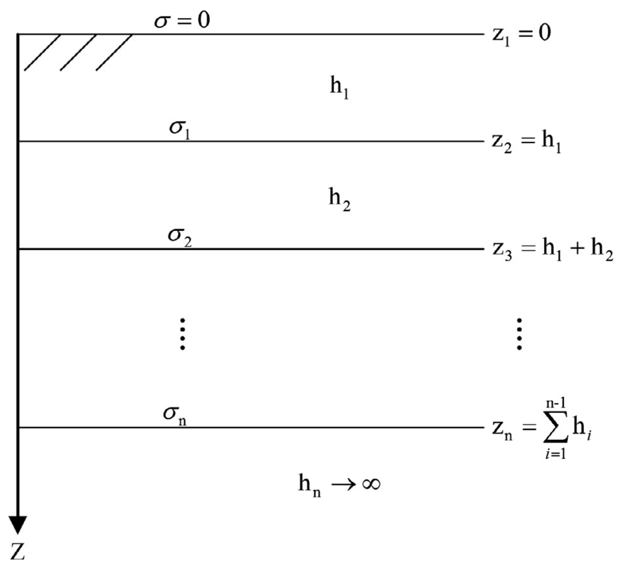


Fig. 2. Layered Earth model for calculating the induced geoelectric field.

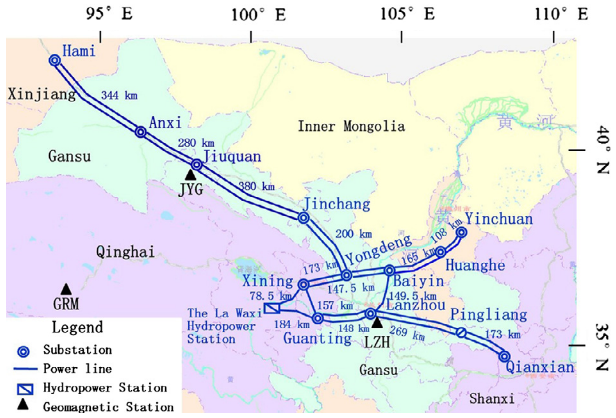


Fig. 3. Chinese Northwest 750 kV power grid. Three geomagnetic observatories (GRM, LZH, and JYG) are also shown on the map. (The WMQ observatory is not located in the area of this map.)

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

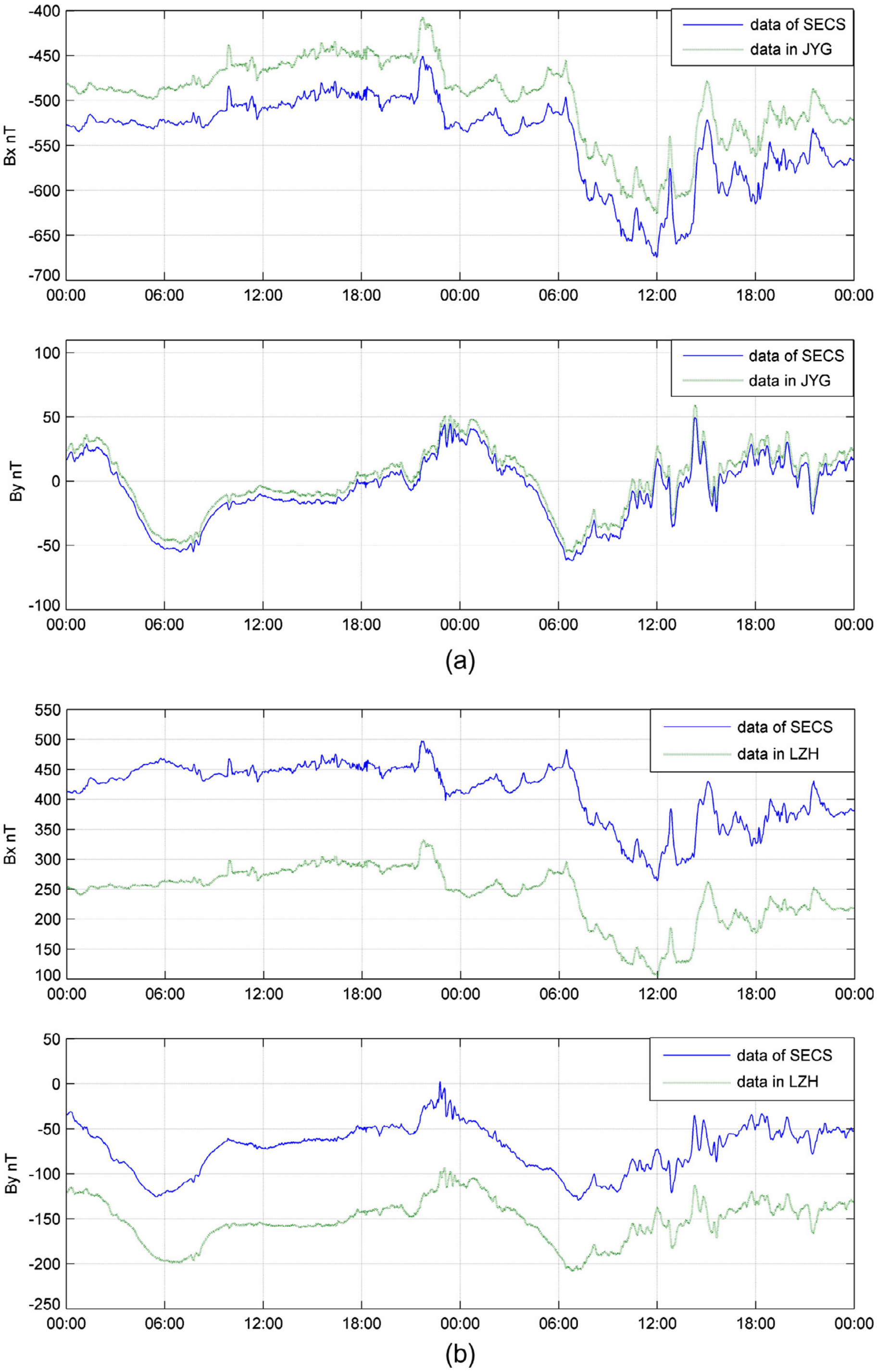


Fig. 4. Measured magnetic data and the SECS-derived magnetic data on 29–30 May 2005. The horizontal axis is the UT time in hours (a) magnetic data from JYG observatory and the SECS-derived magnetic data for Jiuquan substation and (b) magnetic data from LZH observatory and the SECS-derived magnetic data for Yongdeng substation.

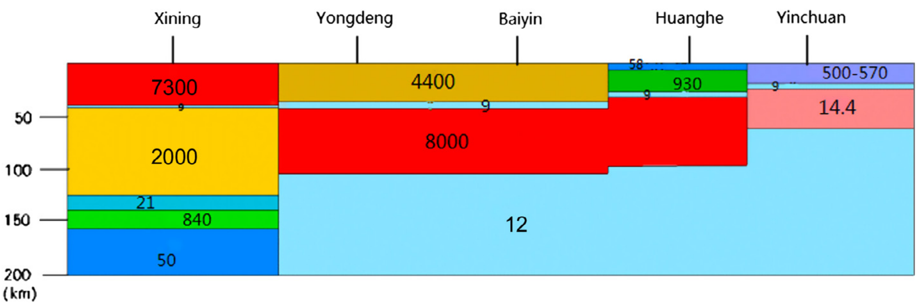


Fig. 5. Resistivity for the section Xining-Yinchuan along 750 kV power transmission lines.

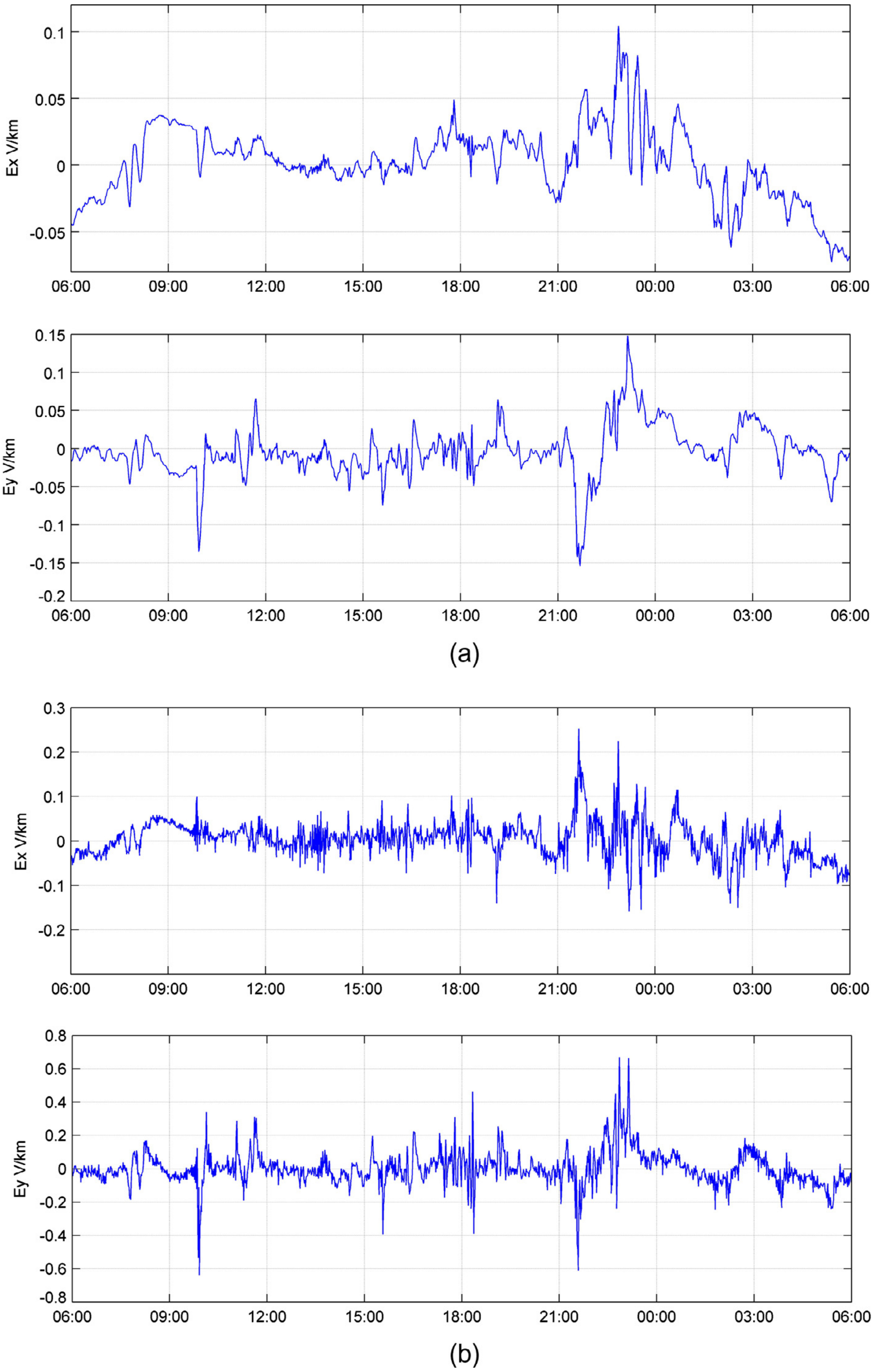


Fig. 6. Calculated geoelectric fields at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) E-Jiuquan and (b) E-Yongdeng.

$$Z_m = Z_{0m}\frac{1 - L_{m+1}e^{-2k_m h_m}}{1 + L_{m+1}e^{-2k_m h_m}} \tag{4}$$

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.:

$$V_{AB} = \int_A^B \vec{E} \cdot \overleftarrow{\mathrm{d}l}\,. \tag{5}$$

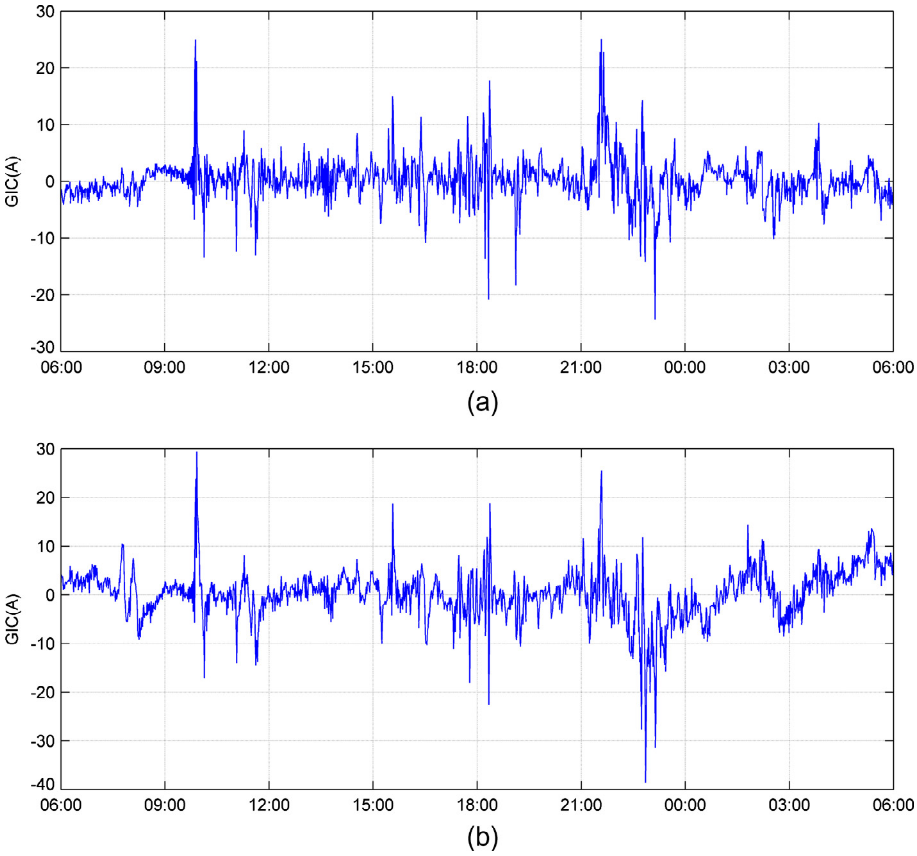


Fig. 7. Calculated GIC at two sites (Jiuquan and Yongdeng) of the Chinese Northwest 750 kV power grid on 29–30 May 2005. The horizontal axis is the UT time in hours (a) calculated GIC at Jiuquan substation and (b) calculated GIC at Youngdeng substation.

If the geoelectric field is uniform, the integrals are independent of the paths. Therefore equation (5) can be simplified to

$$V_{AB} = L_{AB}(E_x \sin\theta + E_y \cos\theta) \quad (6)$$

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)

$$\mathbf{I} = (\mathbf{1} + \mathbf{YZ})^{-1}\mathbf{J}, \quad (7)$$

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

$$J_i = \sum_{j=1, j\neq i}^{N} \frac{V_{ij}}{R_{ij}}. \quad (8)$$

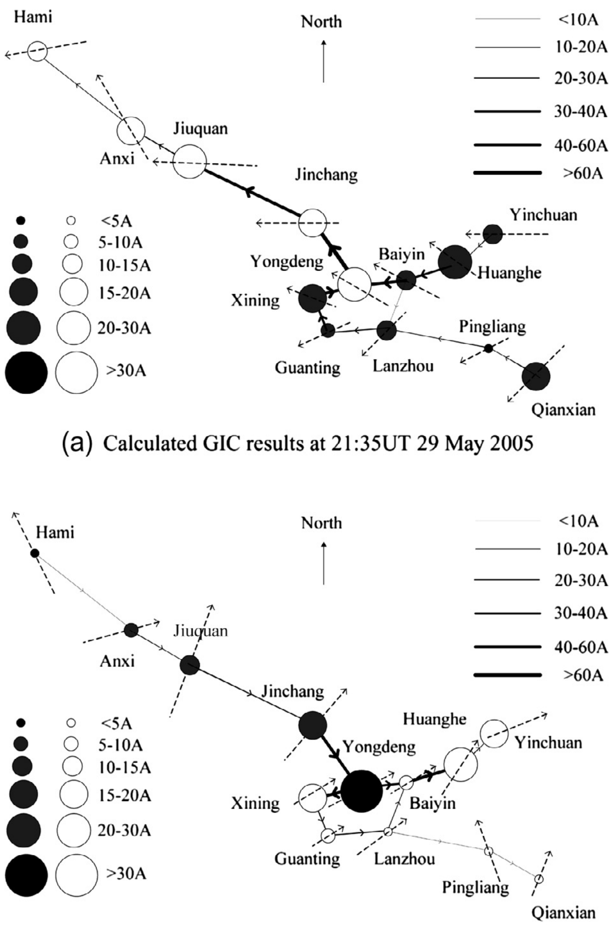
The matrix **J** gives the GIC between the power grid and the earth in the case of ideal groundings, i.e. the grounding resistances are zero making **Z** a zero matrix.

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



(a) Calculated GIC results at 21:35UT 29 May 2005

(b) Calculated GIC results at 22:51UT 29 May 2005

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.

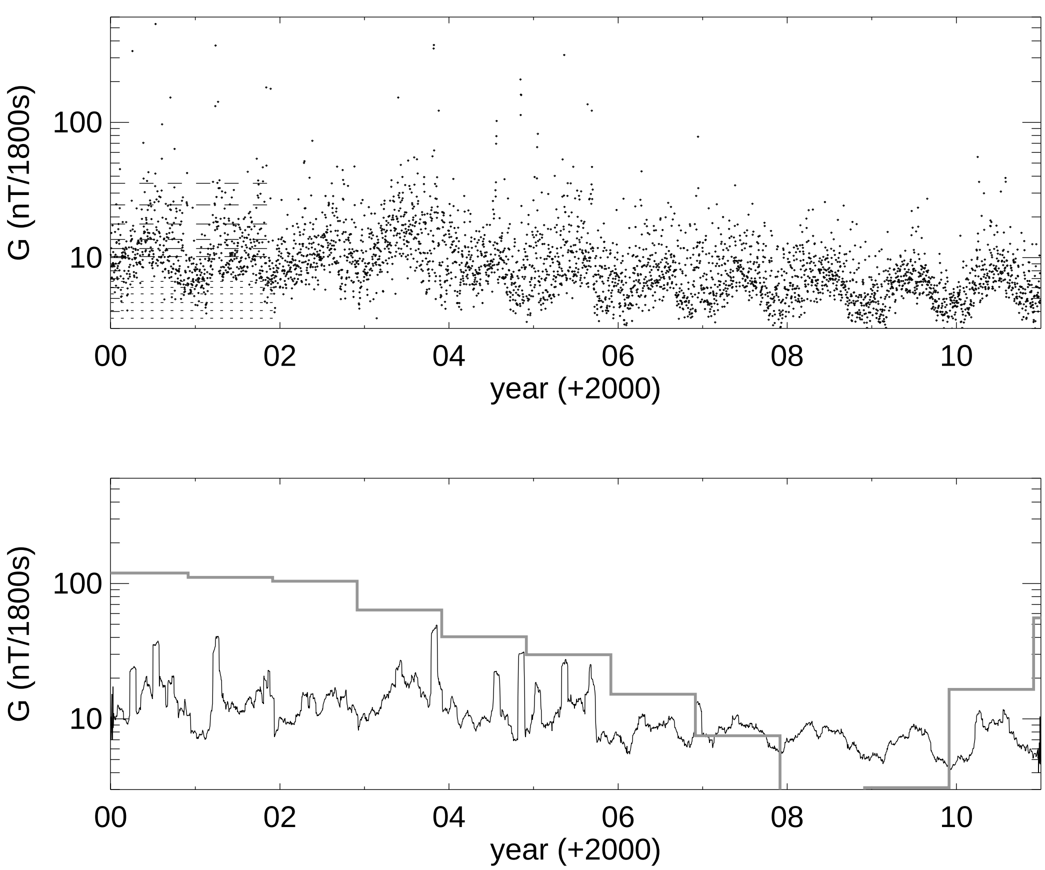

Figure 1. *Daily values $G \equiv max(|dB/dt|)$ based on 30-min. intervals (dots; nT/1800s) characterizing geomagnetic variability for the contiguous United States versus time (in years since 2000). The 27-d running mean is shown by the solid line. The levels for the 98, 95, 90, 82, 75, and 67 percentiles 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.*

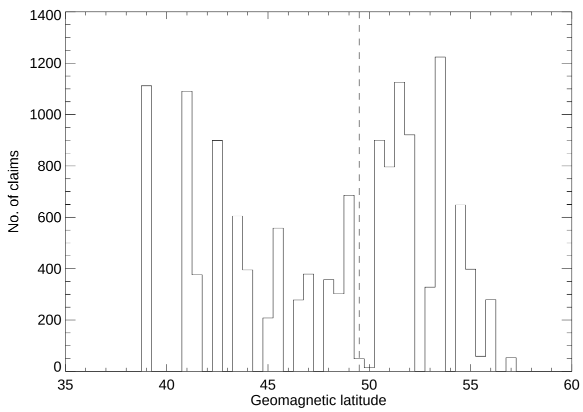

Figure 2. *Number of insurance claims sorted by geomagnetic latitude (using the central geographical location of the state) in 0.5° bins. The dashed line at 49.5° is near the median geomagnetic latitude of the sample (at 49.3°), separating what this paper refers to as high-latitude from low-latitude 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

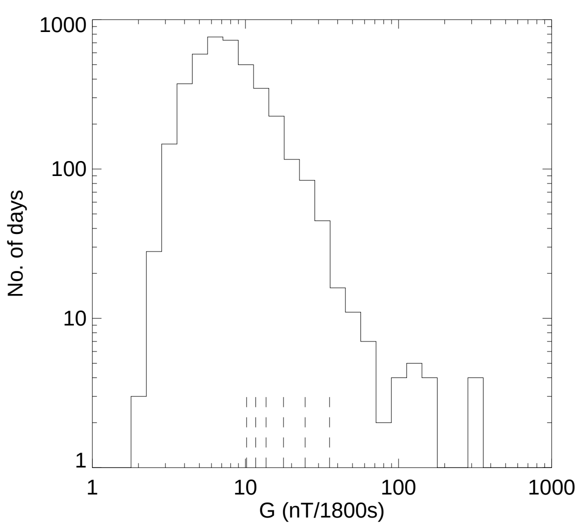

Figure 3. *Histogram of the number of days between 2000/01/01 and 2010/12/31 with values of $G \equiv max(|dB/dt|)$ in logarithmically spaced intervals as shown on the horizontal axis. The 98, 95, 90, 82, 75, and 67 percentiles (ranking G from low to high) are shown by dashed lines.*

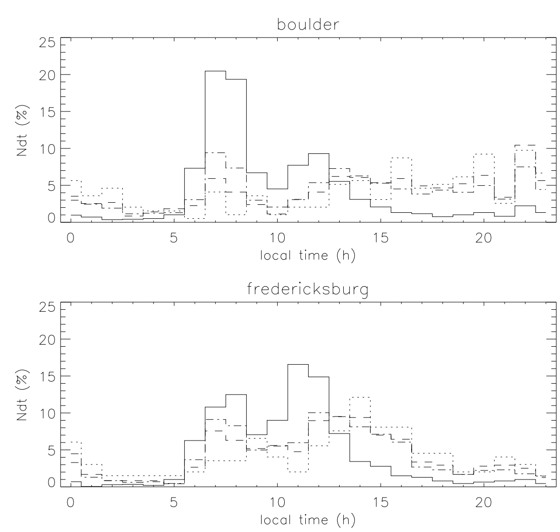

Figure 4. *Normalized histograms of the local times for which the values of $G \equiv max(|dB/dt|)$ reach their daily maximum (top: Boulder; bottom: Fredericksburg). The solid histogram shows the distribution for daily peaks for all dates with G values in the lower half of the distribution, i.e., for 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.*

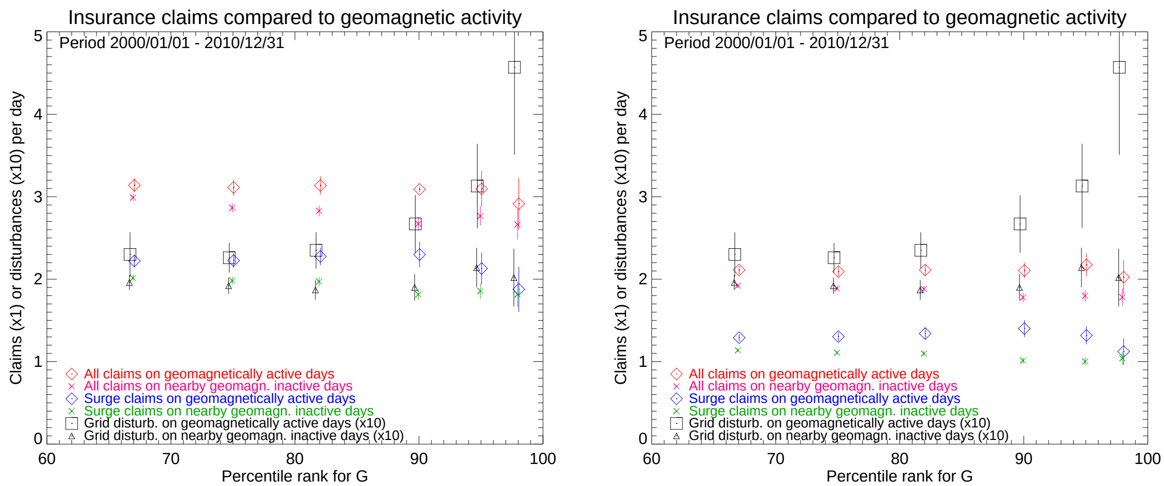

Figure 5. *Claims per day for the full sample of insurance claims (set* A *left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). Each panel shows mean incident claim frequencies* $n_i \pm \sigma_c$ *(diamonds) for the most geomagnetically 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

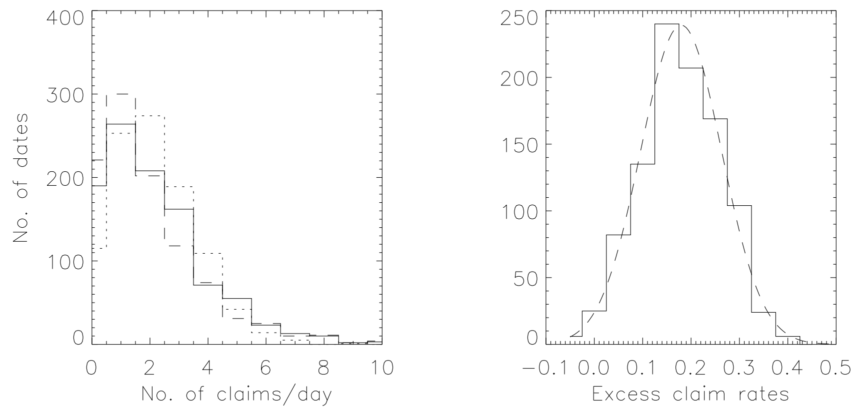

Figure 6. *(left) Distribution of the number of claims per geomagnetically active day for set* B *for the top 25% of* G *values (solid) compared to that for the distribution of control dates (divided by 3 to yield the same total number of dates; dashed). For comparison, the expected histogram for a random 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.*

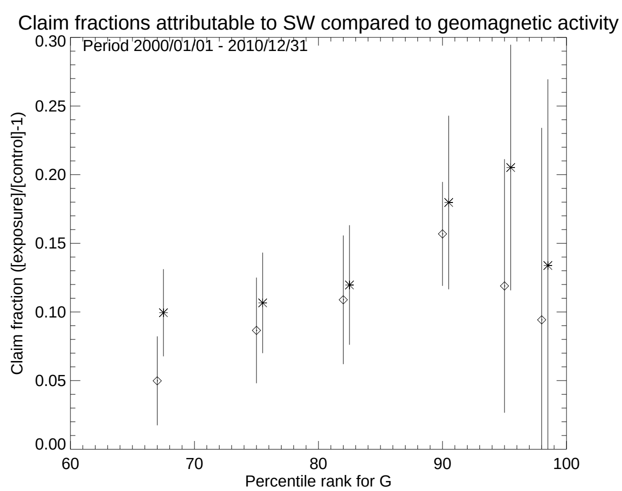

Figure 7. *Relative excess claim frequencies statistically associated with geomagnetic activity (difference between claim frequencies on geomagnetically active dates and the frequencies on control dates as shown in Fig. 5, i.e.,* $(n_i - n_c)/n_c$ *) for the full sample (A; diamonds) and for the sample (B; asterisks) from which claims were removed attributable to apparently non-space-weather related causes.*

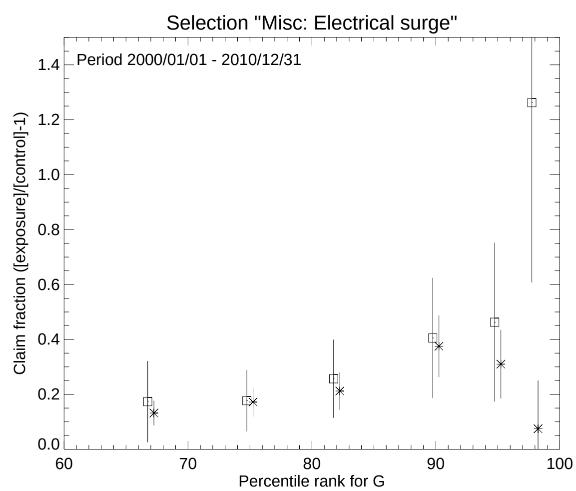

Figure 8. *Same as Fig. 7 but for sample* B *limited to those claims attributed to "Misc.: Electrical surge" (asterisks) (for 57% of the cases in that sample), compared to the fraction of high-voltage power-grid disturbances statistically associated with geomagnetic activity (squares).*

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 $\sigma_e =$

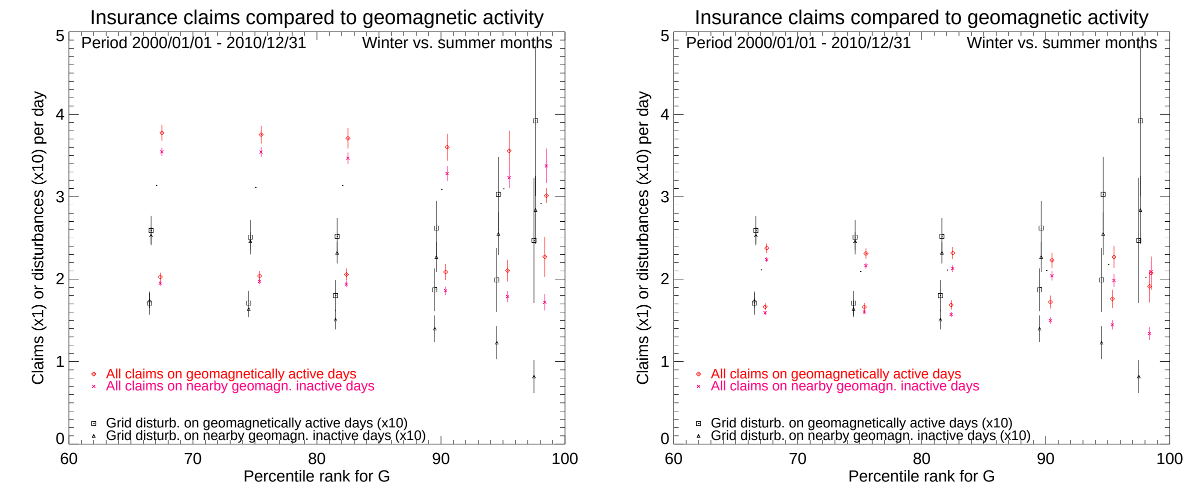

Figure 9. *As Fig. 5 but separating the winter half year (October through March) from the summer half year (April through September), for the full sample of insurance claims (set* A*, left) and the sample from which claims likely unrelated to any space weather influence have been removed (set* B*, right). 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

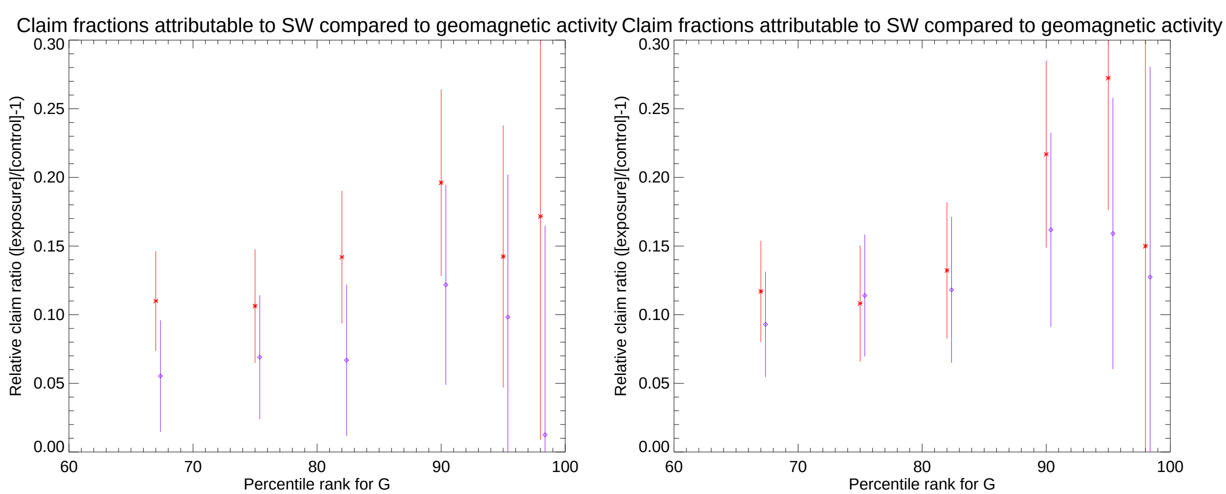

Figure 10. *Relative excess claim frequencies* $(n_i - n_c)/n_i$ *on geomagnetically active dates relative to those on control dates for geomagnetic latitudes below* $49.^\circ 5$ *N (asterisks, red) compared to those for higher latitudes (diamonds, purple; offset slightly to the right) for the percentiles 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.

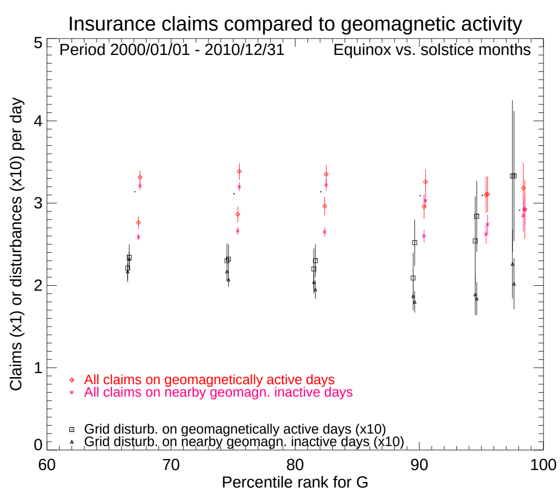

Figure 11. *As Fig. 9 but separating the months around the equinoxes (February-April and August-October) from the complementing months around the solstices, for the full sample of insurance claims (set* A*). Values for the equinox periods are shown offset slightly towards the left of the percentiles 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.

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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 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

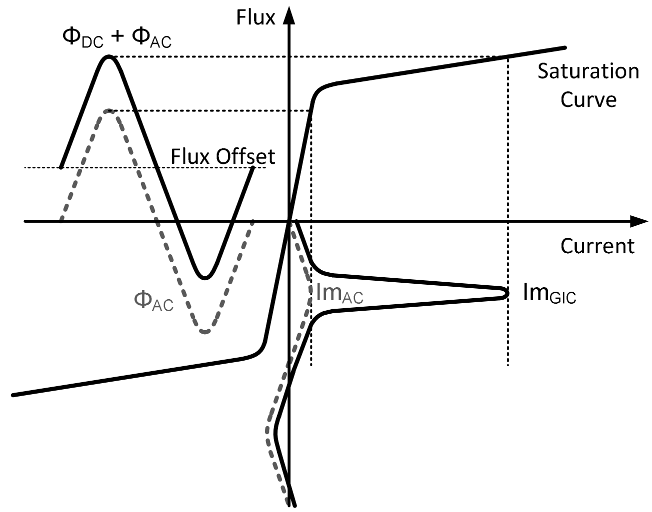

Fig. 1. Half-cycle saturation of the transformer core due to GIC

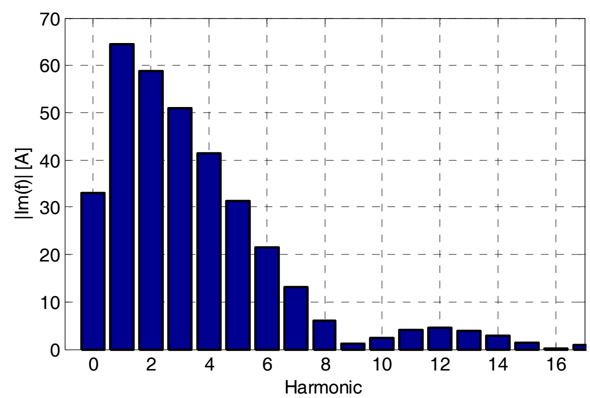

Fig. 2. Harmonics of the transformer magnetizing current at GIC=33.3 A/phase (100A at the neutral of the transformer)

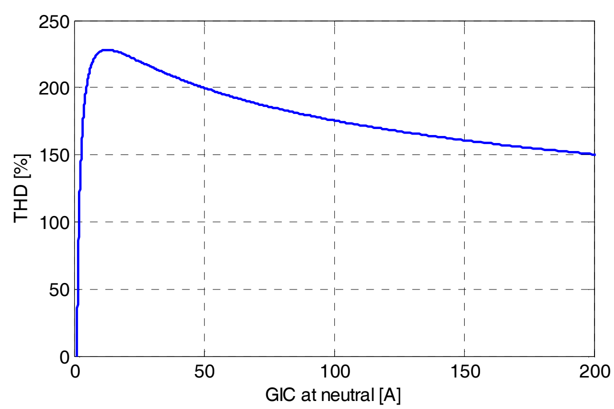

Fig. 3. Total Harmonic Distortion (THD) of the transformer magnetizing current under various GIC levels seen at the transformer neutral

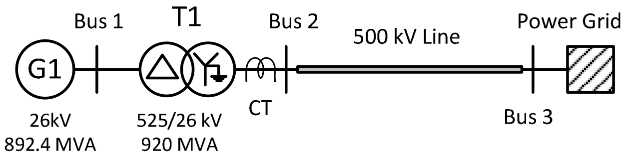

Fig. 4. System under study

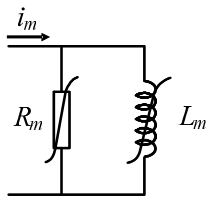

Fig. 5. Transformer core model with a dynamic core loss resistance

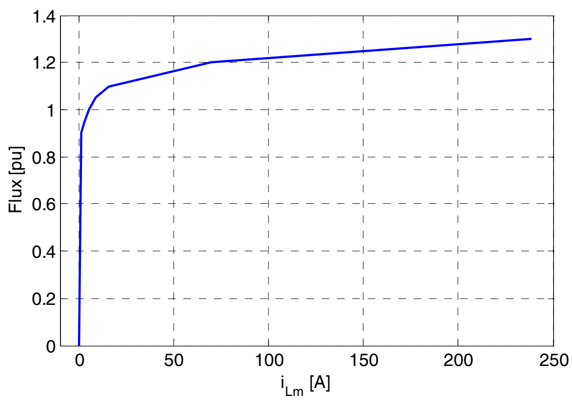

Fig. 6. Saturation curve of the GSU transformer

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

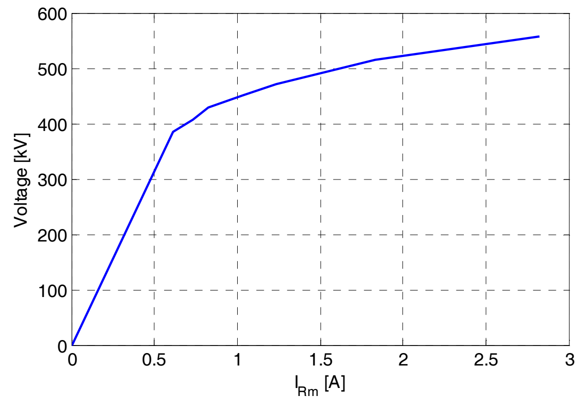

Fig. 7. Characteristic of the dynamic core loss resistance of the GSU transformer

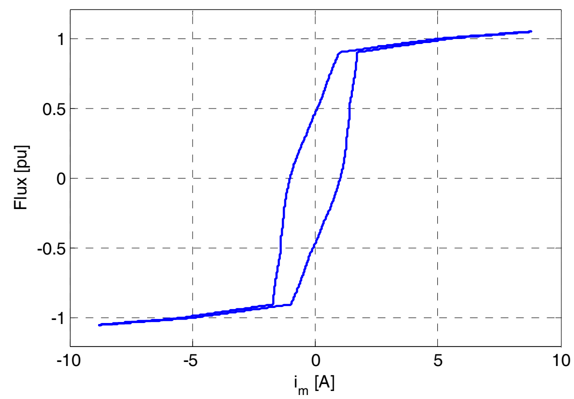

Fig. 8. Overall characteristic of the GSU transformer core at 1.1pu excitation based on the dynamic core loss model of Fig. 5 and the characteristics of Figs. 6 and 7.

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

$$I_2 = 8\text{-}(MVA\text{-}350)/300, \tag{1}$$

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],

$$I_{2eq} = \sqrt{I_2^{\,2} + \sum_n \sqrt{\frac{n+i}{2}} I_n^{\,2}}\,, \tag{2}$$

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.

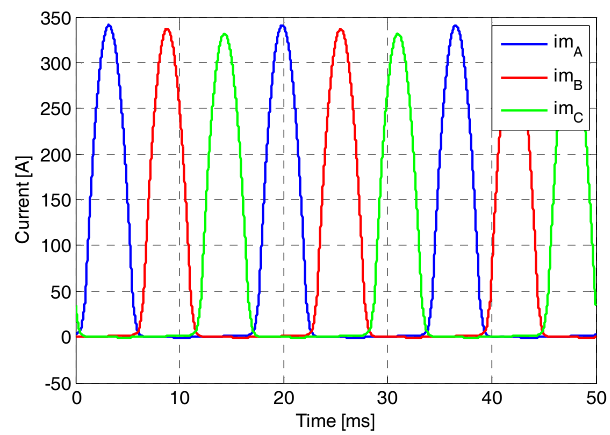

Fig. 9. Generator current harmonics under GIC of 200A at the neutral of the GSU transformer

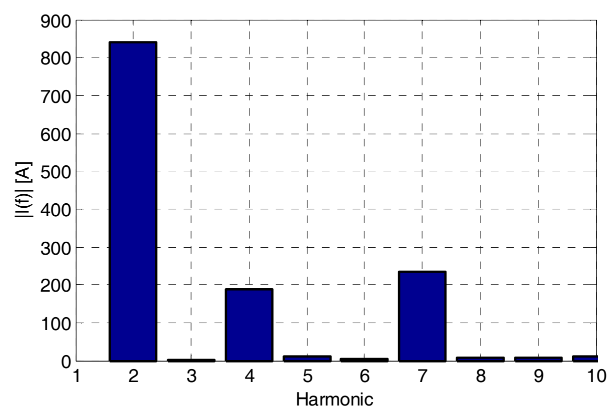

Fig. 10. Generator current harmonics under the transformer neutral GIC of 200A

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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[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

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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.

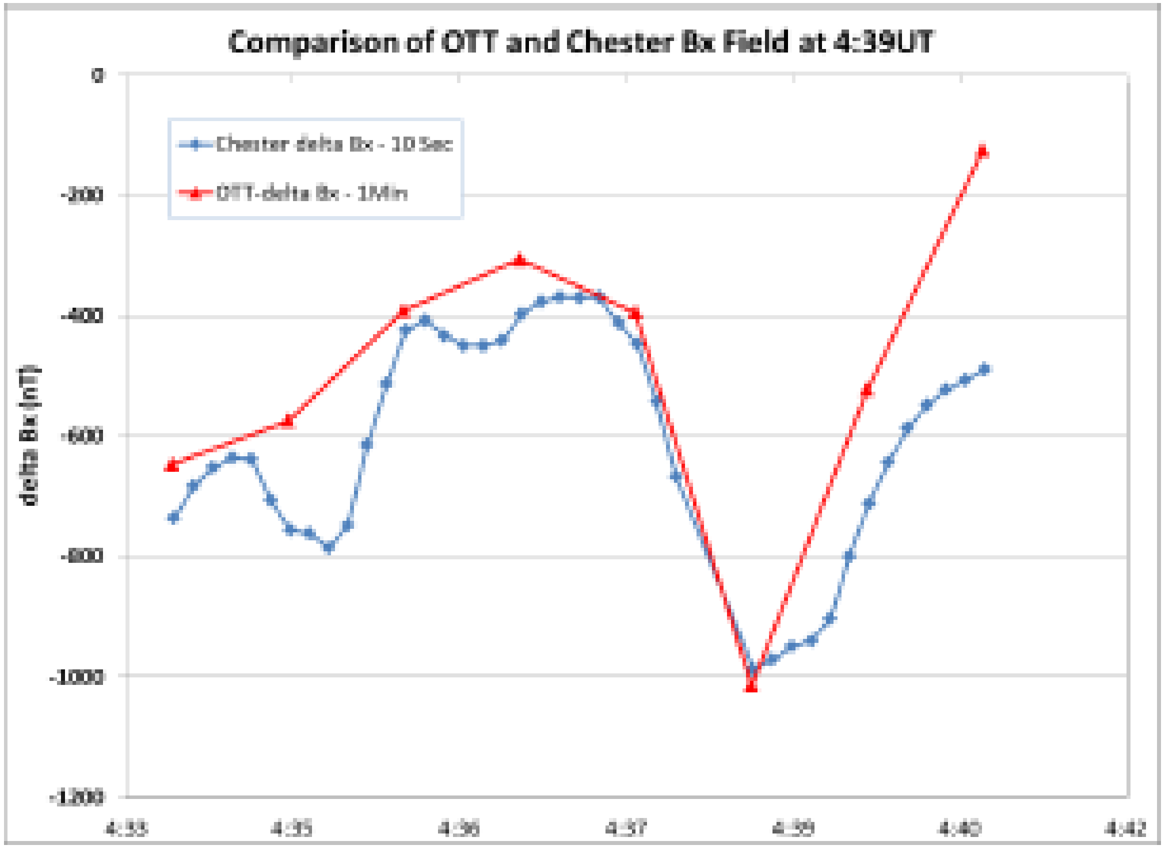
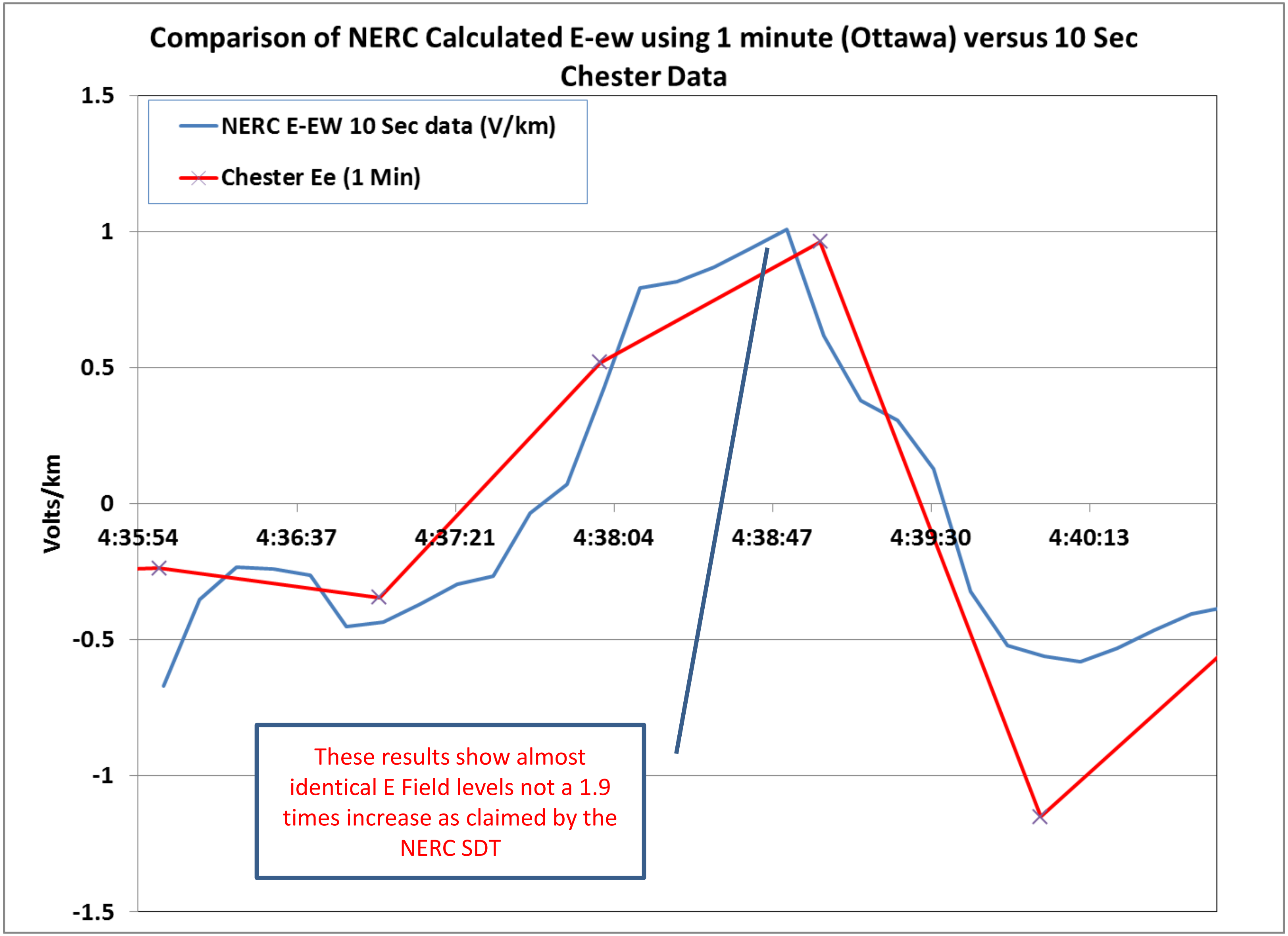


Figure 15 – Observation of Bx at Ottawa and Chester during peak impulse at time 4:39UT.

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.

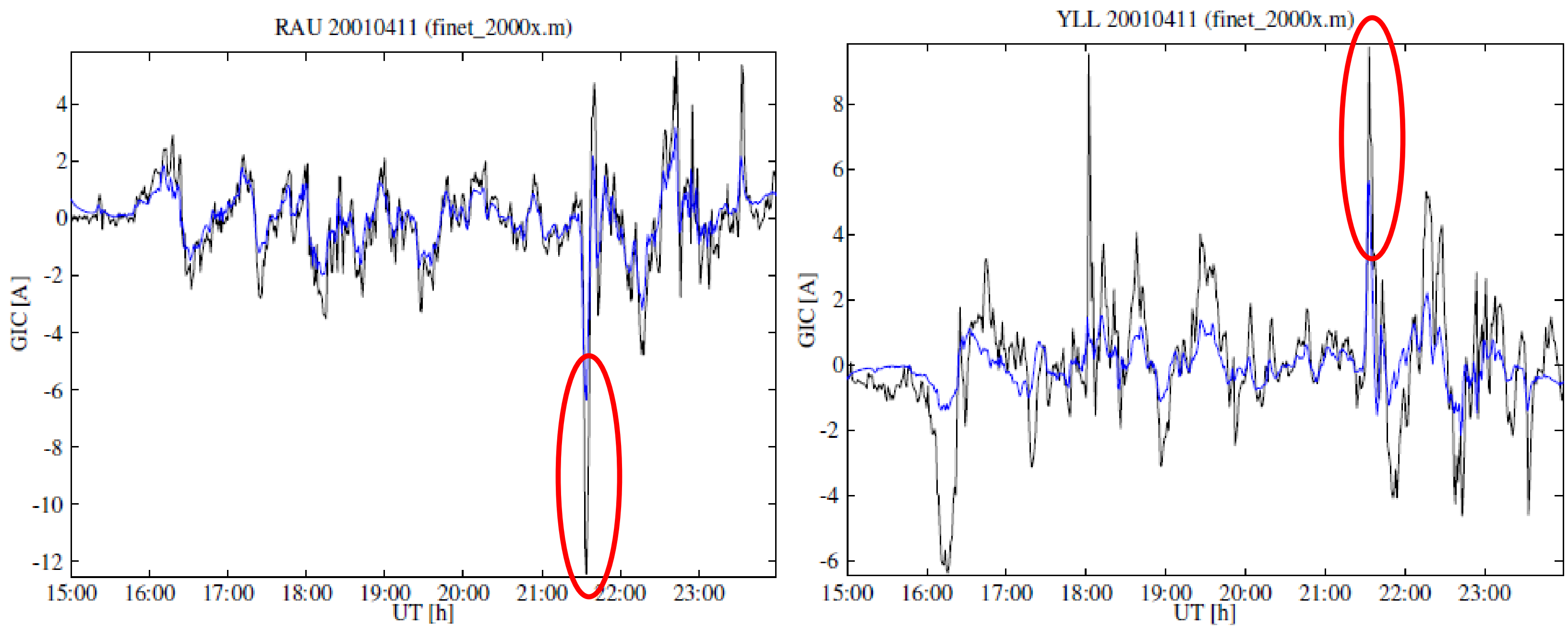
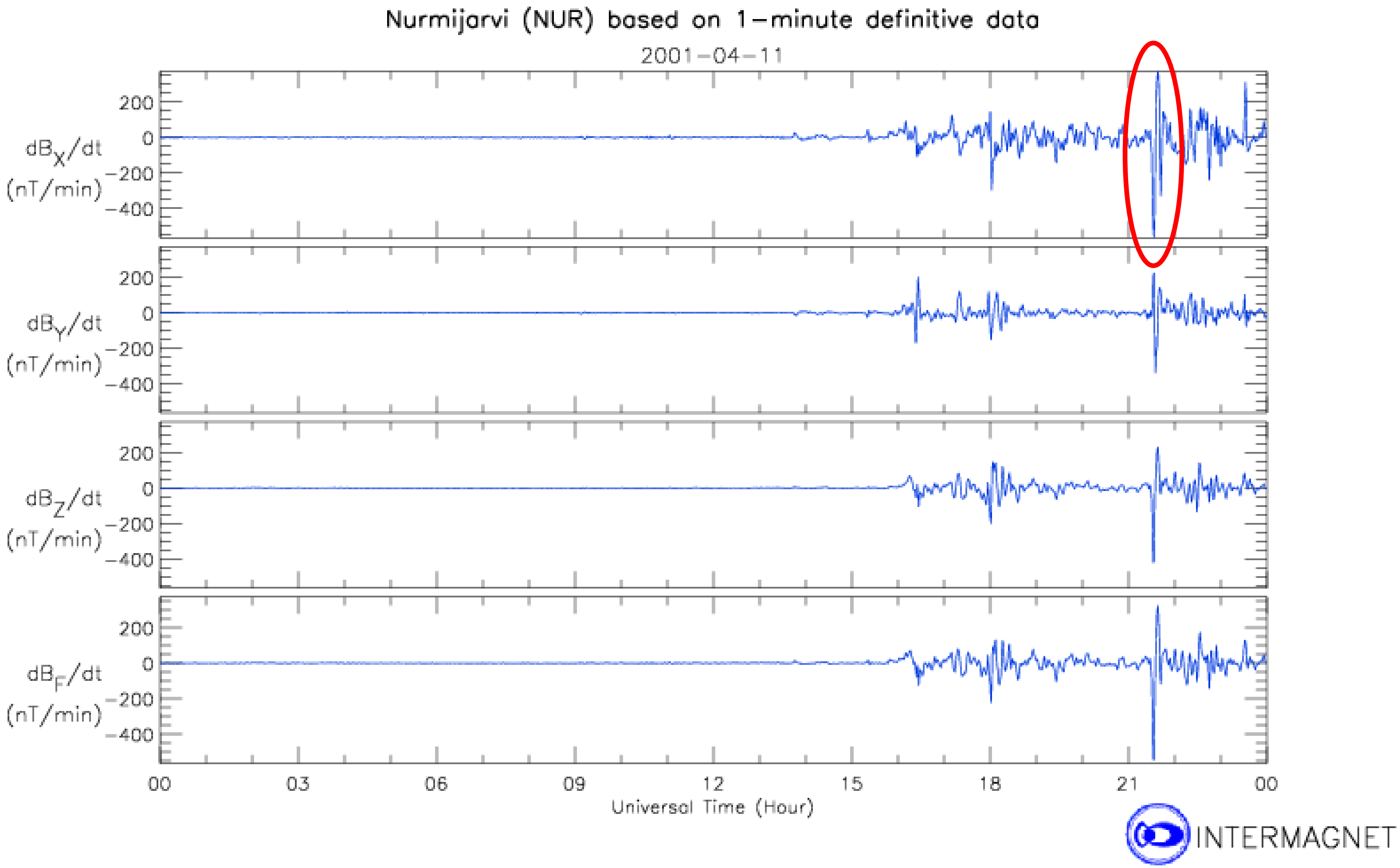


Fig. 8. Measured (black line) and modelled (blue line) geomagnetically induced currents at the Rauma (RAU) and Yllikkälä (YLL) 400 kV transformer stations on 11 April 2001.

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:

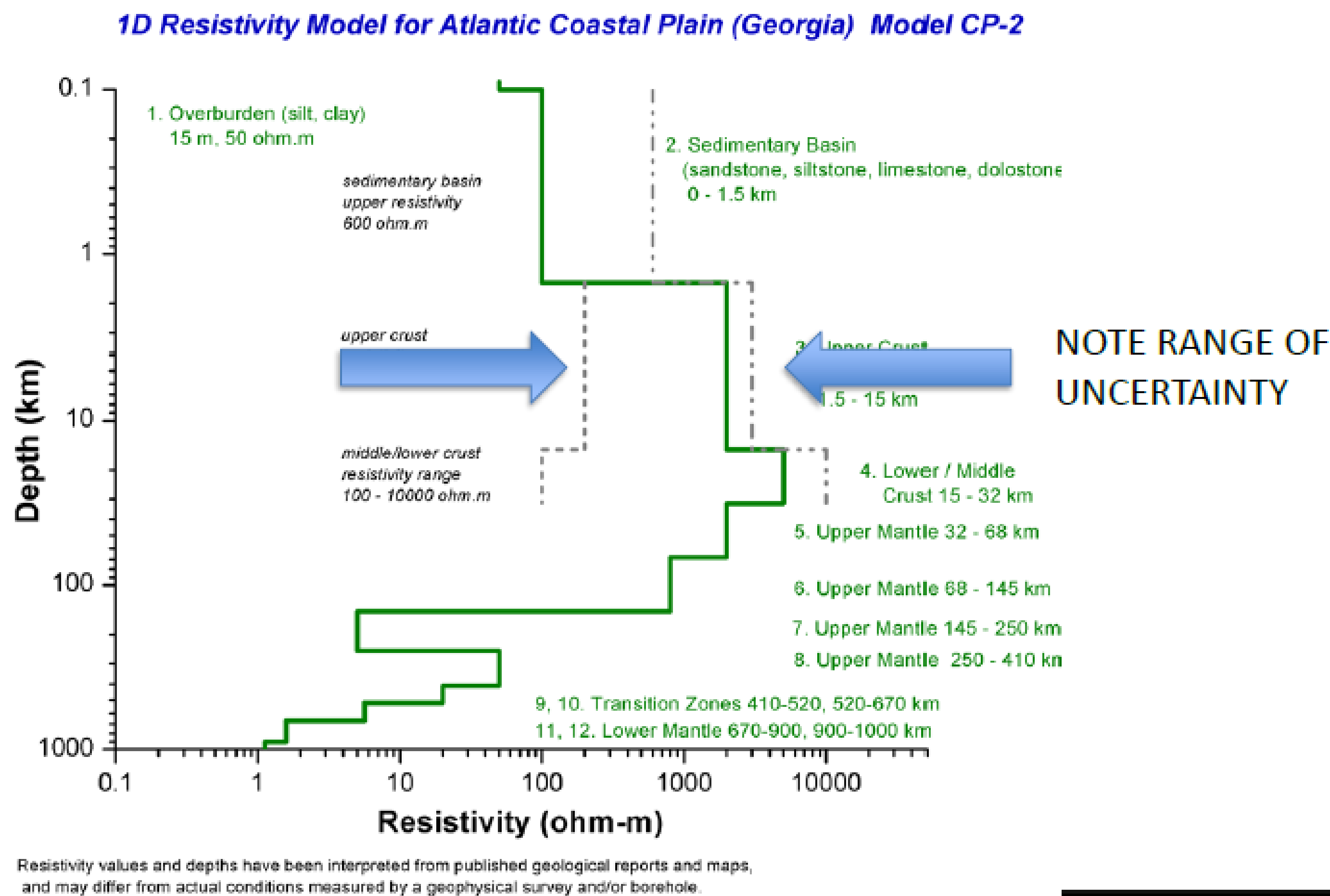
> *"The commenter's approach for using GIC data to calculate geoelectric fields is valid when an accurate power system model, ground conductivity model, specific power system configuration at the time of measurement, and high data rate magnetometer data is available. Calculations are not accurate without 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



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

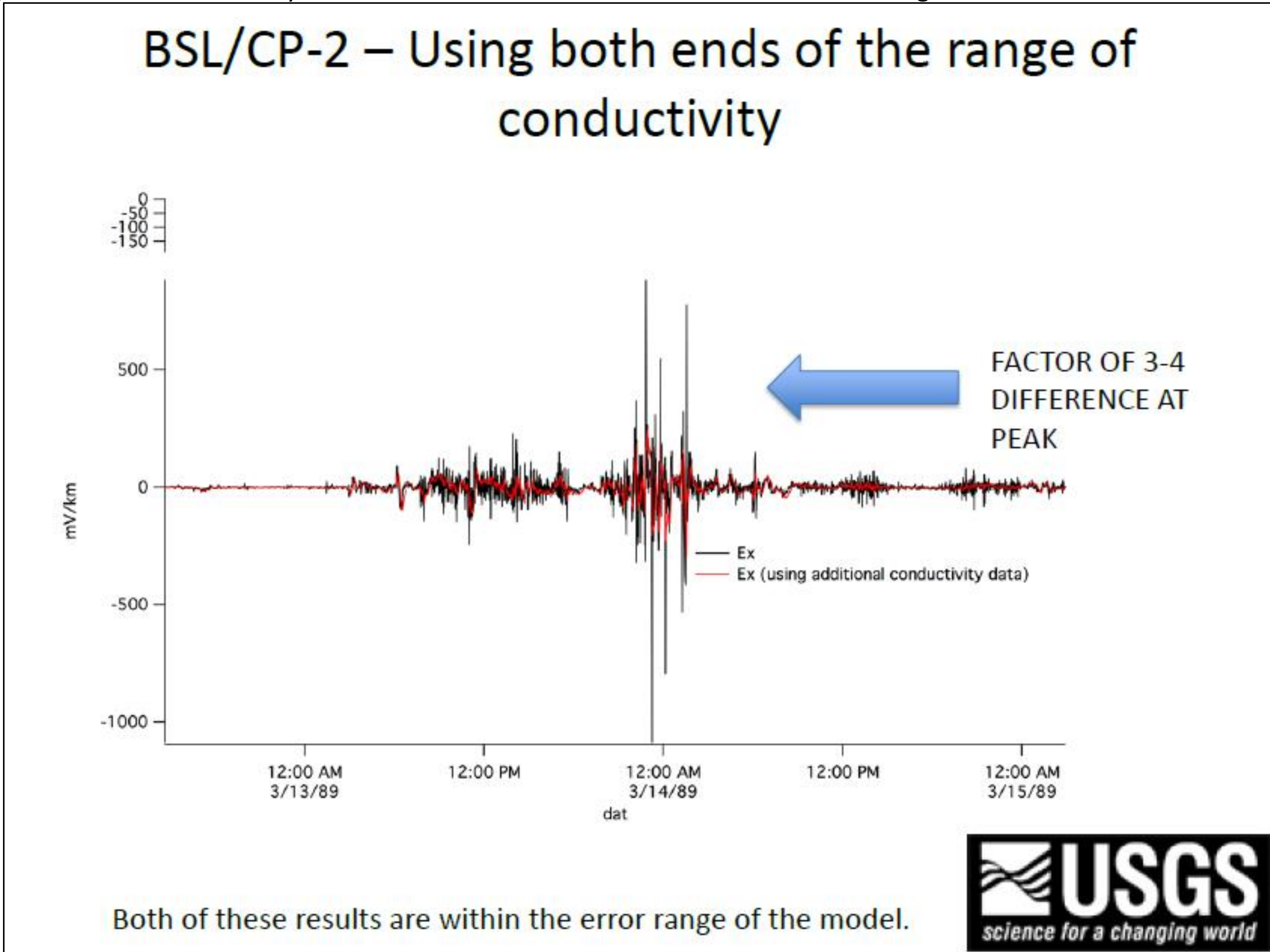


Figure 7 – NERC Draft Standard Benchmark Geo-electric field scaling factors

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.

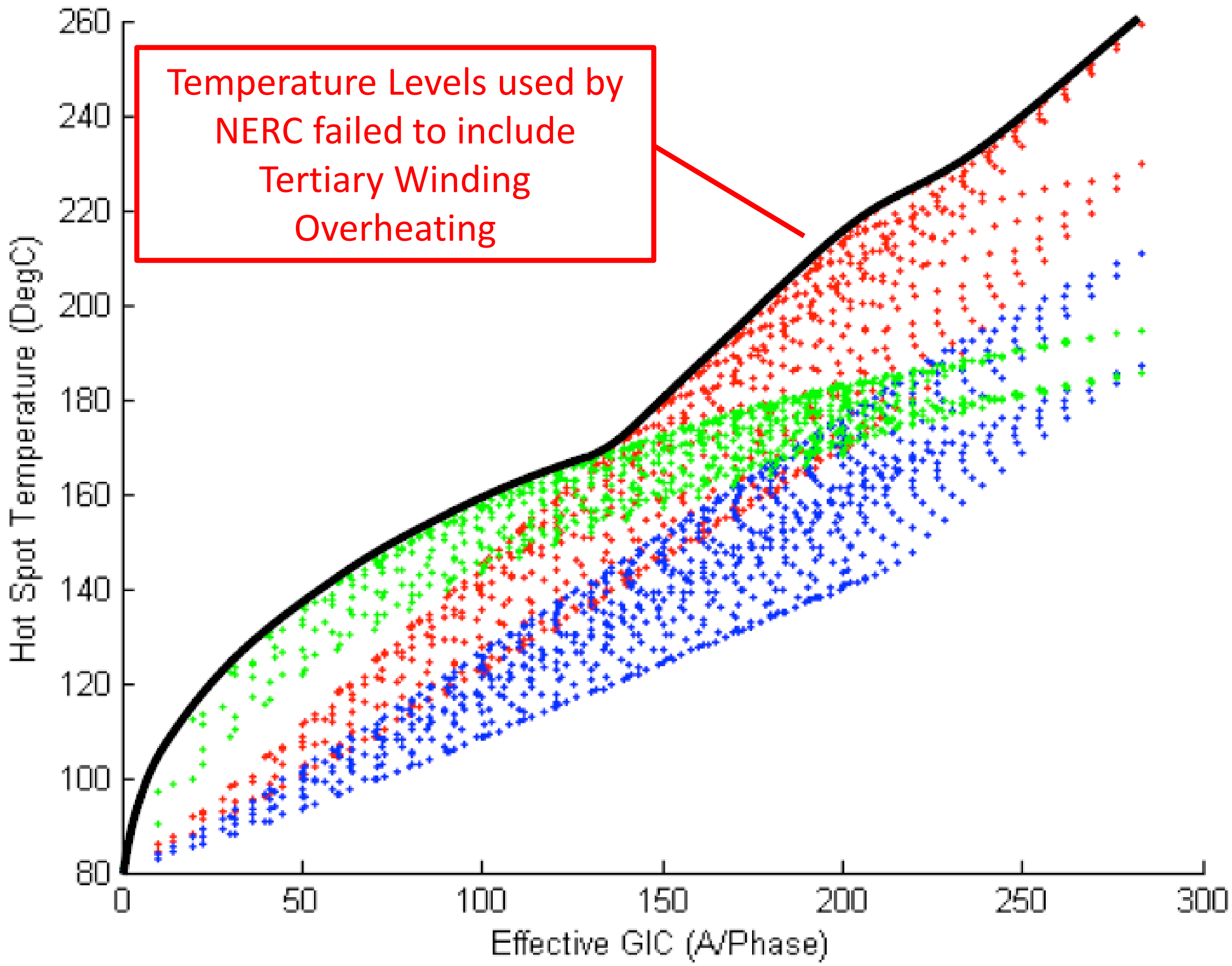


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: Screening model [2]. Blue: Fingrid model [3]. Green: SoCo model [4].

Figure 2 – Plot of NERC Table 1 Upper Bound of Peak Metallic Hot Spot Temps

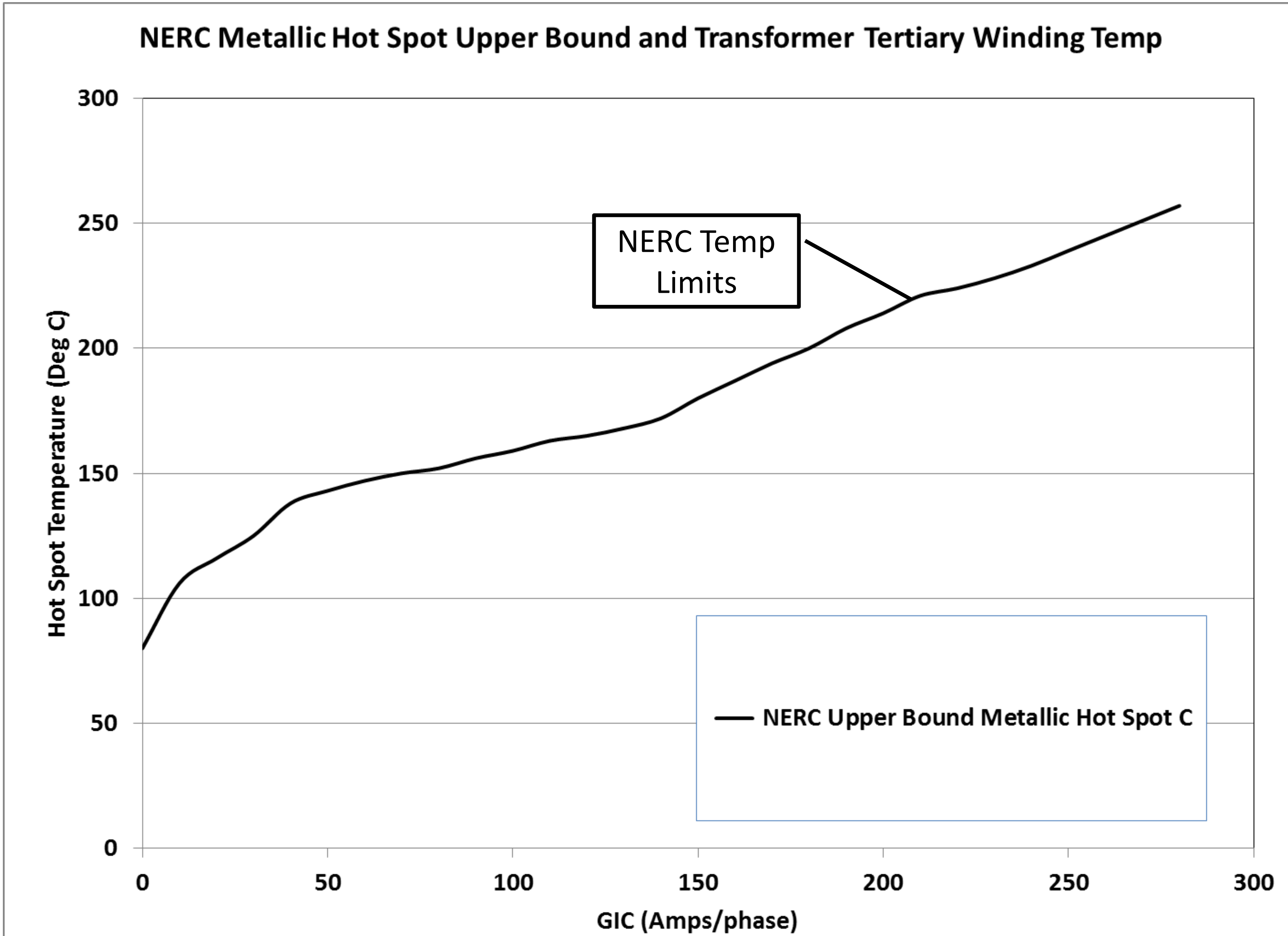
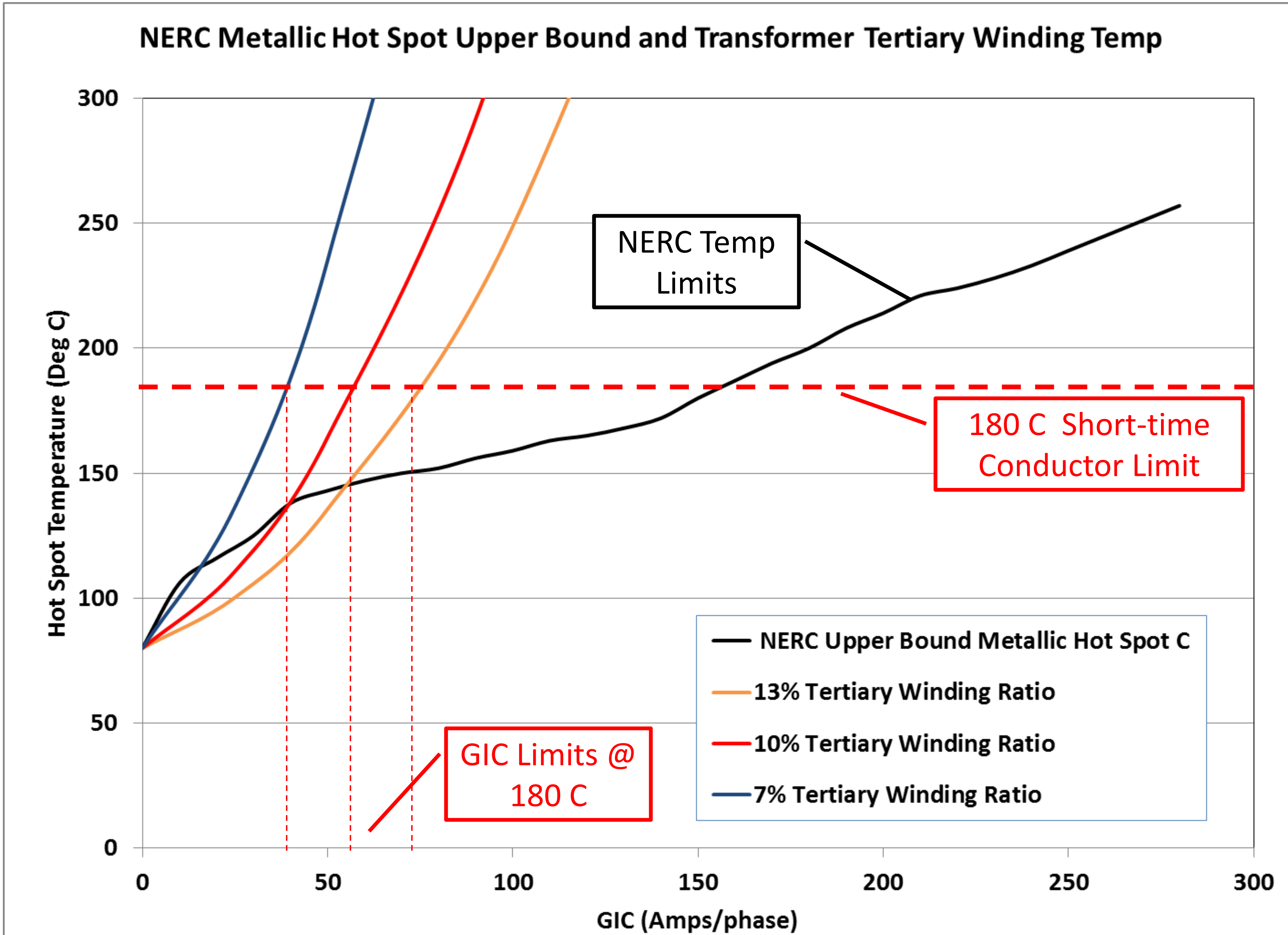


Figure 3 – Plot of NERC Table 1 & Ignored Tertiary Winding Conductor Temperatures



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

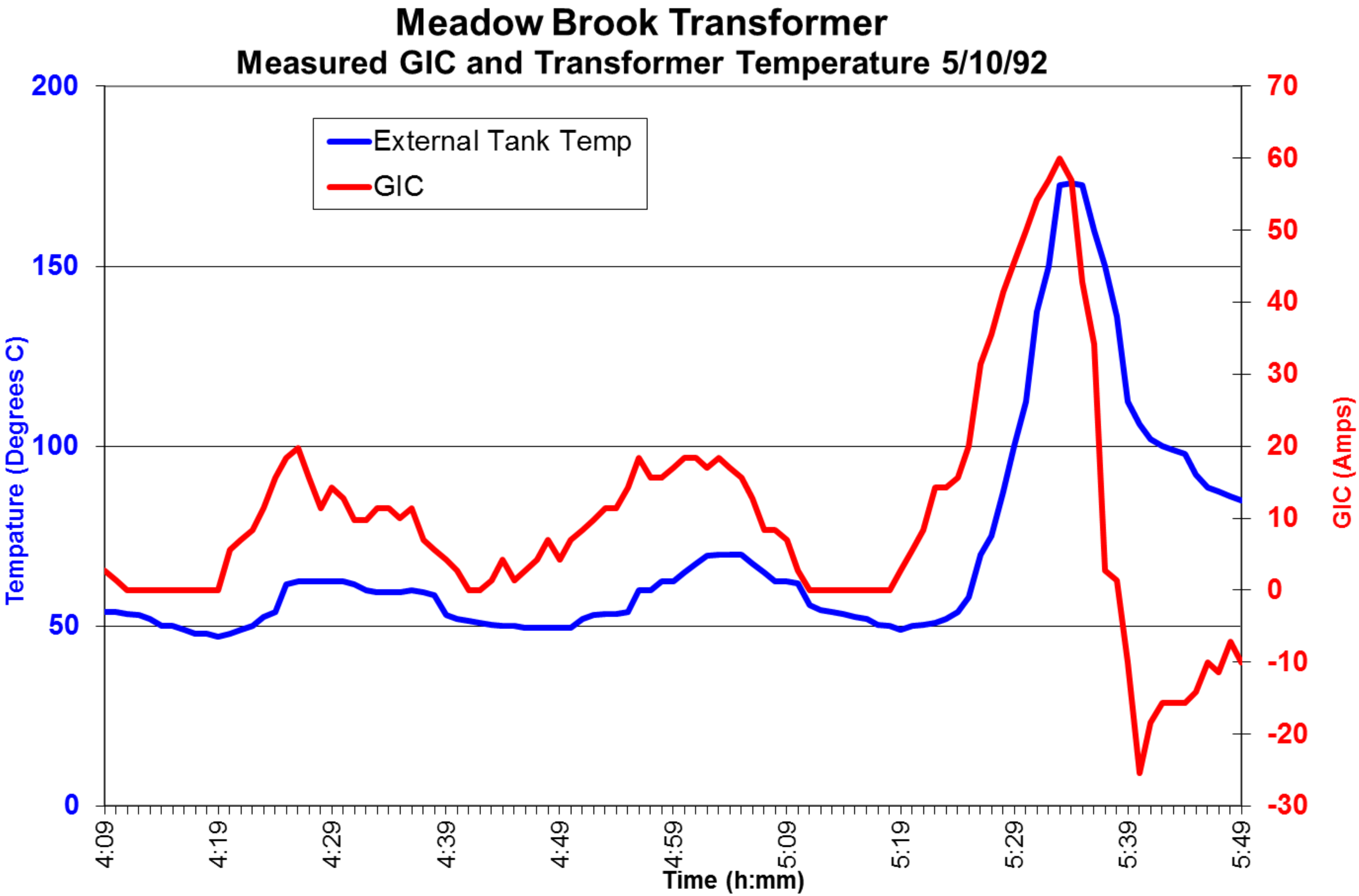


Figure 4 – Plot of Observed GIC and Transformer Temperatures at Meadow Brook

(Note to convert GIC Neutral to GIC Amps/phase, divide by 3)

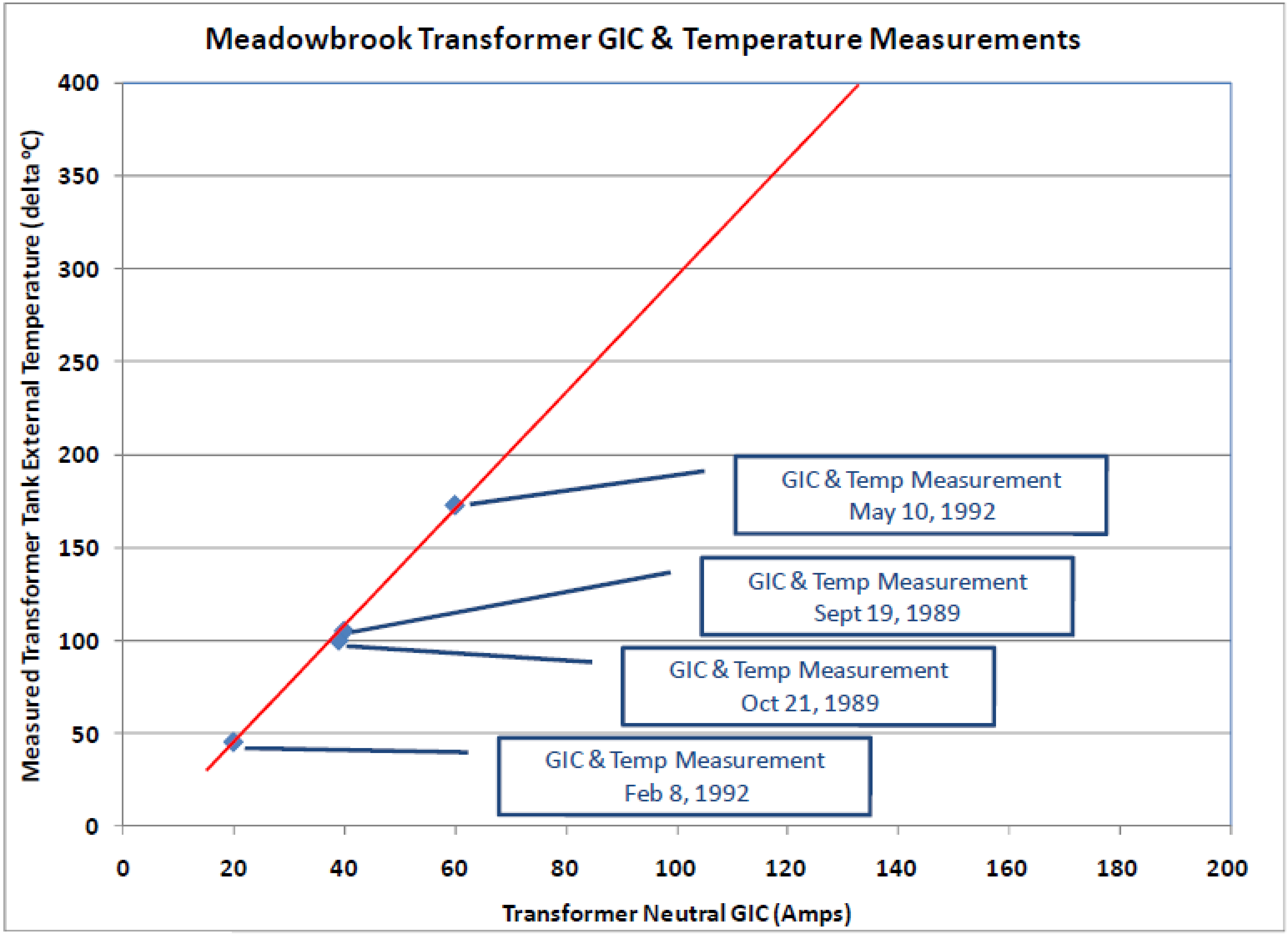


Figure 5-4 - Observation Points of GIC and Hot Spot temperatures and GIC-Temperature Trend Line.

Storm-R-112, August 2011

Figure 5 – NERC Asymptotic thermal response versus Meadow Brook actual

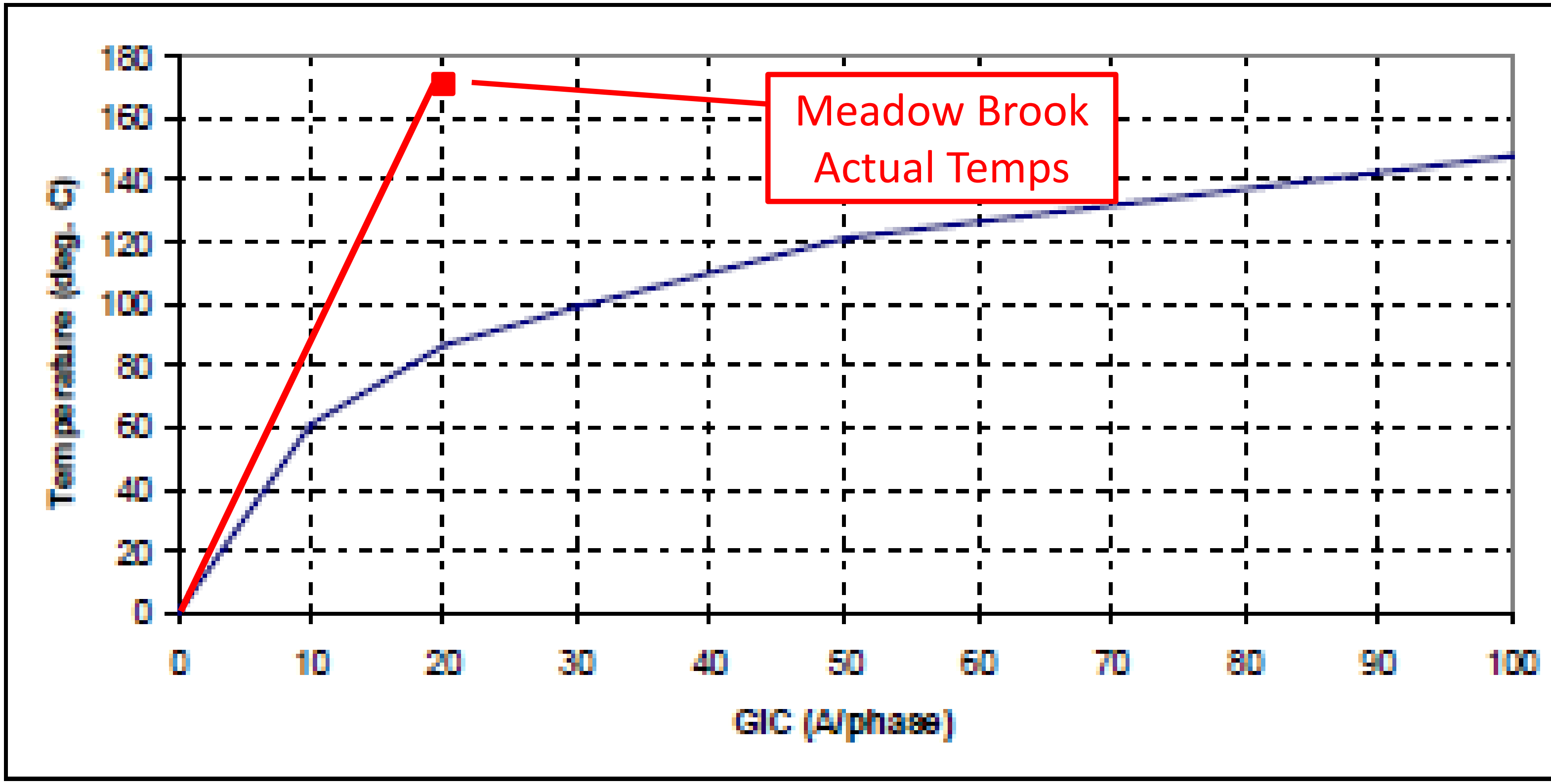


Figure 6: Asymptotic thermal response of the Flitch plate of a 400 kV 400 MVA single-phase core-type autotransformer.

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.

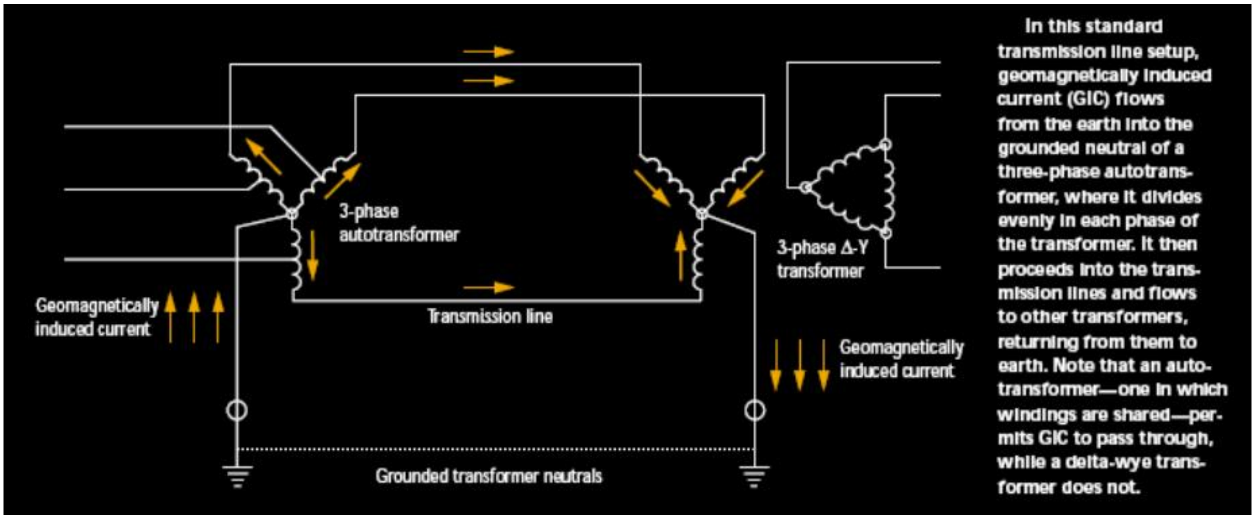

FIGURE 1
Conducting Path for GICs[8]

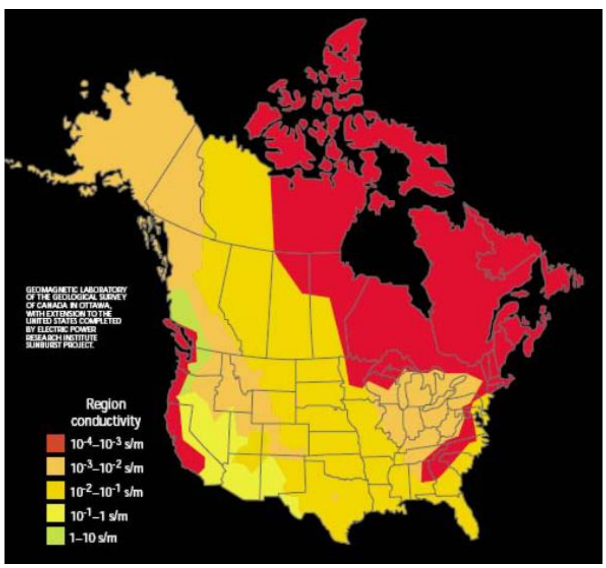

FIGURE 2
Earth Conductivity in US & Canada[8]

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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.

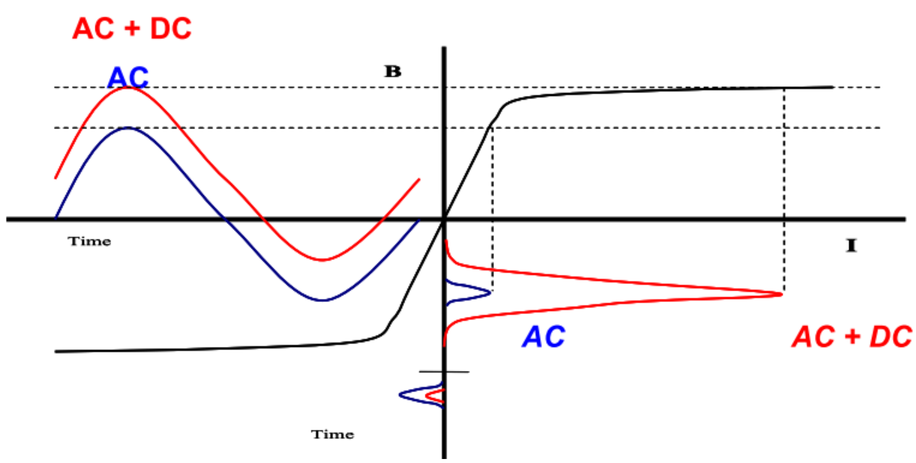

FIGURE 3
Part Cycle, Semi Saturation of Transformer Cores[9]

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.

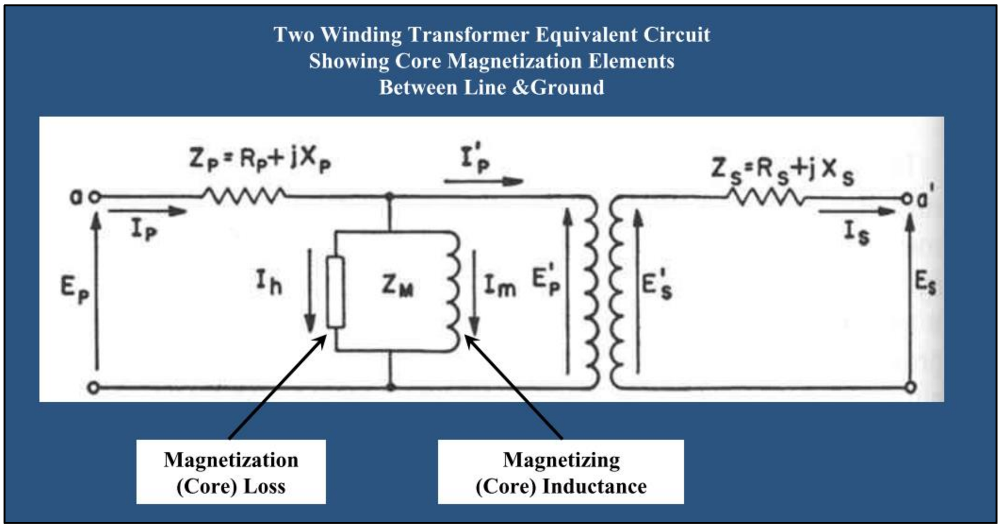

FIGURE 4
Transformer Equivalent Circuit[10]

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

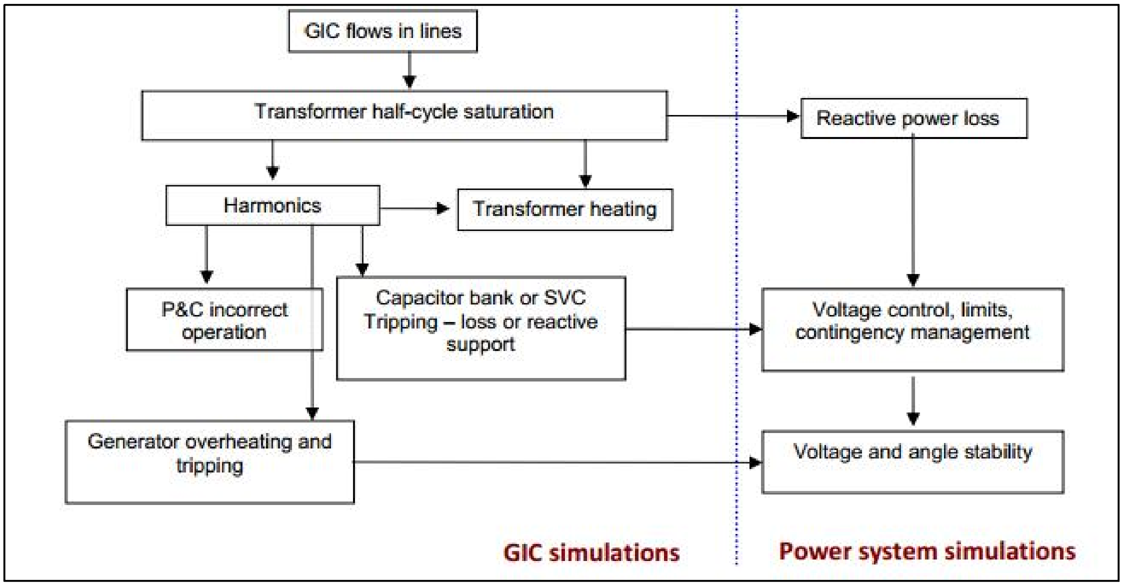

FIGURE 5
From NERC: Effects of GIC in a High Voltage Transmission Network[18]

<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,

[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.

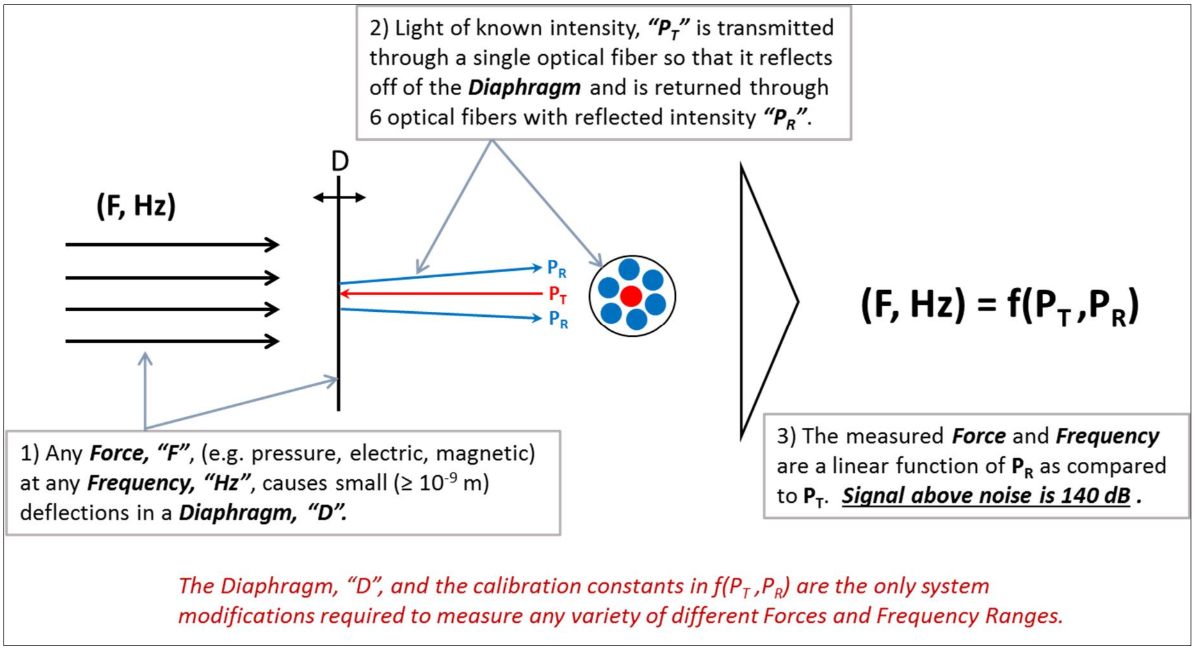

Figure 6
Intensity Modulated Optical Sensing – Fundamental Concept

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.

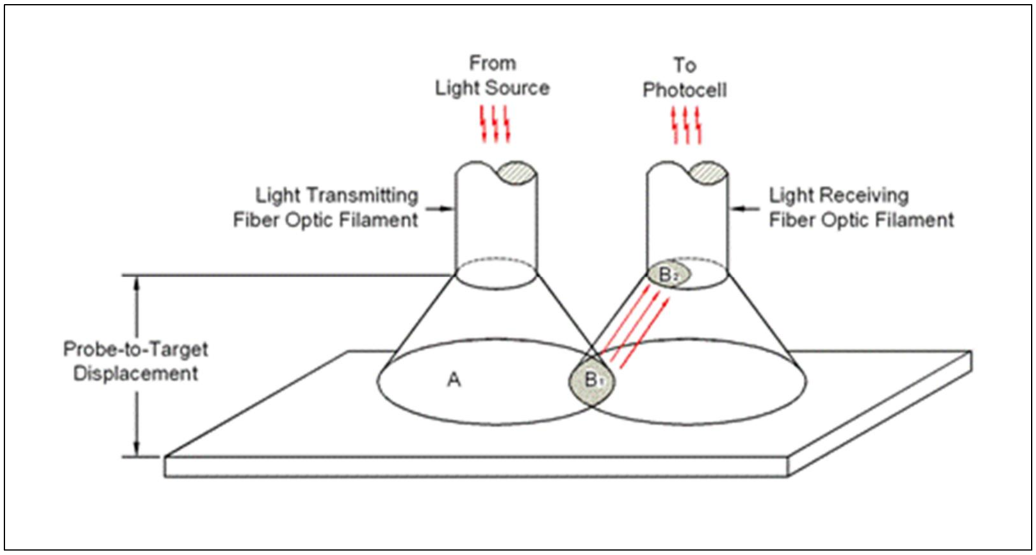

FIGURE 7[23]
P_R Decreases as Displacement between Probe and Diaphragm Decreases

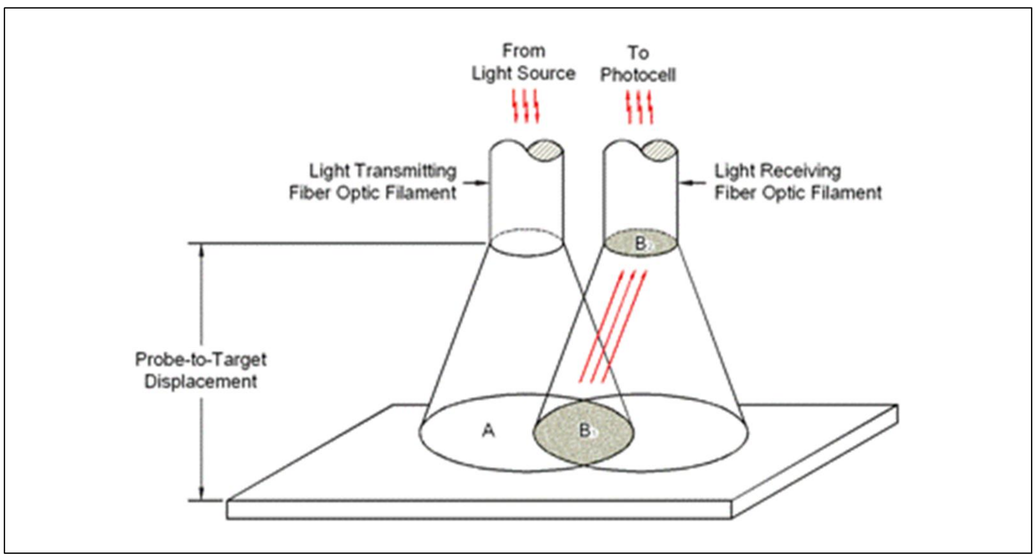

FIGURE 8[24]
P_R Increases as Displacement between Probe and Membrane Increases

Adaptation

Adapting Intensity Modulated Optical Sensors to Measure Electrical Phenomena:

[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.

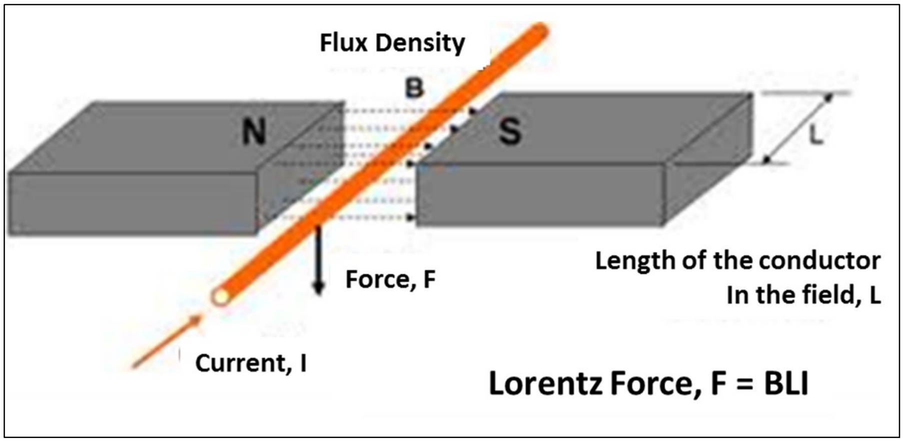

FIGURE 9
Lorentz Law

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.

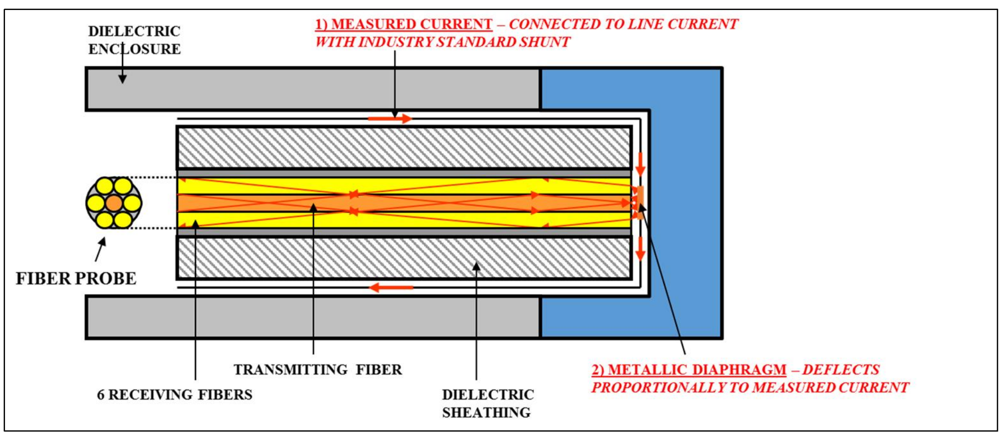

FIGURE 10
Intensity Modulated Fiber Optic Current Sensor

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.

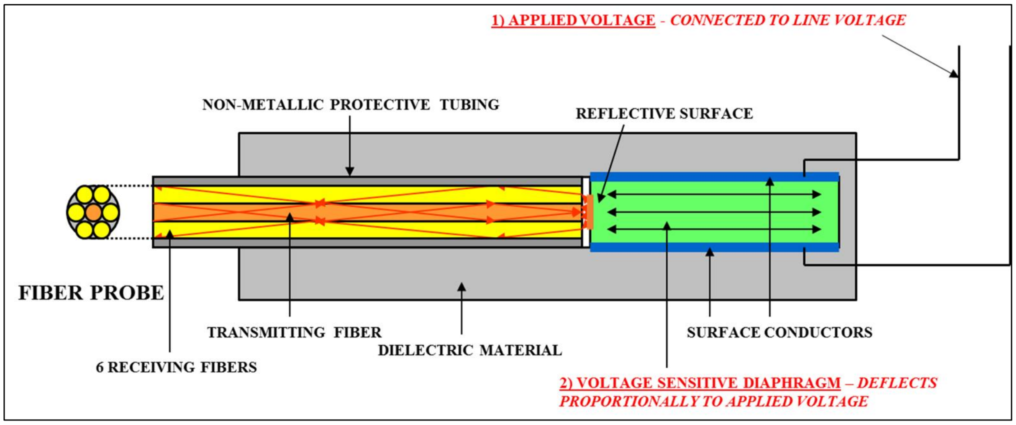

FIGURE 11
Intensity Modulated Fiber Optic Voltage Sensor

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.

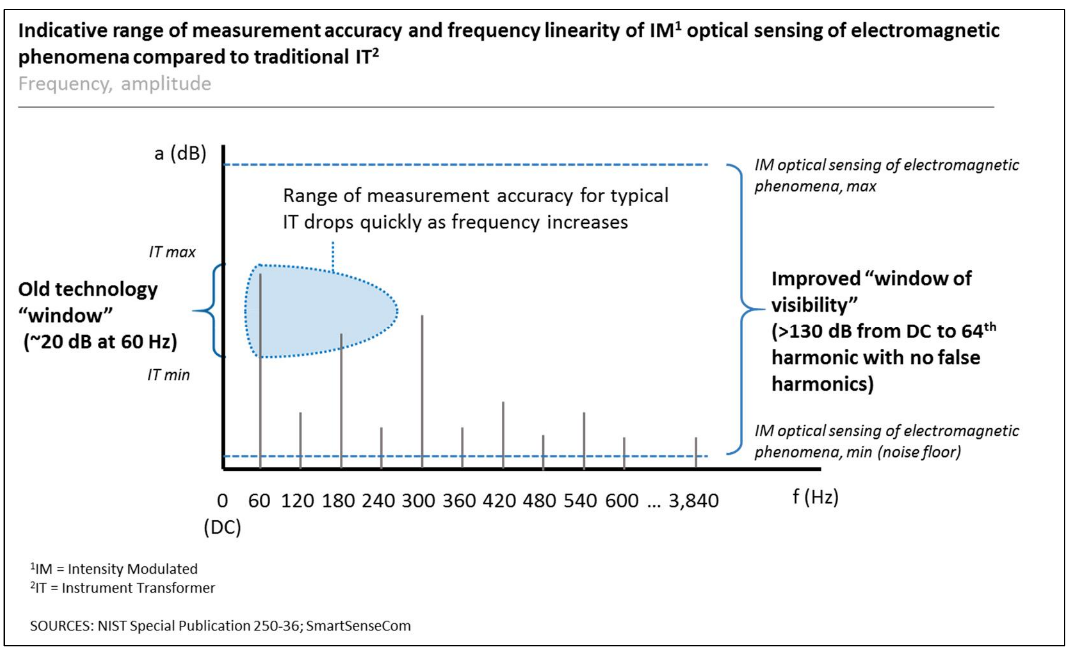

FIGURE 12
Accuracy/ Linearity as a Function of Frequency
(For an IM Optical Monitoring System versus a Conventional IT)

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:

[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.

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