Description of document:	Georgia Public Service Commission (PSC) records concerning the risks to the electric power grid from geomagnetic storms, 2012-2015*
Requested date:	2016
Released date:	05-February-2016
Posted date:	07-November-2016
*Note:	Some records are undated
Source of document:	Open Records Act request Philip Smith Georgia Public Service Commission 244 Washington Street, SW Atlanta GA, 30334-9052 Fax: 770-342-3052 / 404-656-2341

From: "Philip J. Smith"
Date: Feb 5, 2016 4:01:56 PM
Subject: ORA 16-004 --- Response #2 Reports on the effects on the electric grid of electromagnetic storms

Philip J. Smith
Staff Attorney
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Reliability Standards for Geomagnetic	)	**Docket No. RM12-22-000**
Disturbances	)	

COMMENTS OF
THE AMERICAN PUBLIC POWER ASSOCIATION, THE EDISON ELECTRIC INSTITUTE, THE LARGE PUBLIC POWER COUNCIL AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The American Public Power Association ("APPA"), the Edison Electric Institute ("EEI"), the Large Public Power Council ("LPPC") and the National Rural Electric Cooperative Association ("NRECA"), jointly on behalf of their respective member companies (collectively the "Trade Associations") hereby respectfully submits these Comments in response to the Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission ("Commission" or "FERC") on October 18, 2012, in the above-referenced docket. The NOPR proposes to direct the North American Electric Reliability Corporation ("NERC") to create and submit Reliability Standards that address and mitigate the effects of geomagnetic disturbances[1] ("GMDs") on the Bulk-Power System ("BPS") caused by solar events.[2]

---

[1] The Trade Associations' Comments focus exclusively on GMDs as specified in this docket and are not intended to address other phenomena, which are not naturally generated by the effects of the sun.

[2] *See Reliability Standards for Geomagnetic Disturbances*, Notice of Proposed Rulemaking, 141 FERC ¶ 61,045 (2012).

EXECUTIVE SUMMARY

The Trade Associations appreciate the Commission's effort to gather information on this issue, and understand the sentiment favoring action in order to guard the nation's grid from failure. The electric industry takes the risk associated with GMDs very seriously and has worked diligently to better understand GMD effects and to minimize their impacts. GMDs are not a new phenomenon; hence, the industry has learned from various events and believes it has taken effective actions based on current consensus-based knowledge and available tools to address the issues that could challenge reliability. For example, industry has been involved in significant work through NERC's GMD Task Force ("GMDTF"), the Electric Power Research Institute ("EPRI") SUNBURST Project, the National Oceanic and Atmospheric Administration ("NOAA"), and the Goddard Community Coordinated Modeling Center ("CCMC"), which are described in detail in Attachment A of these Comments.[3]

While the Trade Associations share the Commission's goals to protect the BPS against the impacts of GMDs, the NOPR nonetheless raises but does not resolve the many concerns that must be addressed prior to issuance of any final order that would direct NERC to adopt Reliability Standards imposing mandatory changes to the design, operation and control of the BPS. Many aspects of the science surrounding GMDs are still immature, the methods of grid impact analysis remain crude and unrefined, and necessary assessments of the impact of methods of remediation are unproven. In addition, the Trade Associations strongly support the work activities of the NERC

[3] Additionally, the Institute of Electrical and Electronics Engineers ("IEEE") and the International Council on Large Electric Systems ("CIGRE") have commissioned working groups to address GMD impacts on the grid.

GMDTF, an open and inclusive technical group with broad and diverse expertise, and that work requires completion. The Trade Associations strongly recommend that the Commission also support these efforts, as well as other industry activities aimed at addressing GMD issues. Trade Associations also read the NOPR as giving too little weight to contrasting viewpoints, including groups such as the GMDTF and other national laboratory reports[4] that were developed by much broader groups of technical experts, and subject to greater transparency and peer review. The contrasting studies suggest far different opinions of the risks and urgency related to GMDs with respect to the BPS.[5] The Trade Associations also believe that the NOPR inappropriately relies on certain studies characterizing the nature of a possible "100-year" threat scenario to infer that GMD events could place a significant number of transformers at risk for failure or permanent damage. The Trade Associations do not believe that these studies have undergone the rigorous peer review necessary to be relied upon to support the Commission's findings and proposals. These supporting studies are also problematic because they rest upon equations and data that are not transparent and the software used to support such analyses remains largely unavailable.[6]

In the absence of a strong consensus on the technical specification of a severe GMD event that would induce realistic geomagnetic induced current ("GIC") levels that need to be protected against, as well as the immaturity of tools necessary to accurately

[4] *See* PNNL-21033, Geomagnetic Storms and Long-Term Impacts on Power Systems and Special Reliability Assessment Interim Report: *Effects of Geomagnetic Disturbances on the Bulk Power System* (2011) ("PNNL-21033").

[5] Accordingly, the Trade Associations describe below specific concerns with the ORNL/Metatech Report.

[6] Software to assess GIC withstand capability of transformers may be available to equipment manufacturers, but is not directly available to the member companies of the Trade Associations.

determine where and to what level GIC might have detrimental effects, the Trade Associations believe the Commission would be asking the industry to make assessments of risk and apply solutions at a point when these tools are simply incapable of doing so without creating significant unknown risks to reliability that could be of a greater degree than any known risk resulting from a severe GMD event. Moreover, without such a consensus, it is extremely challenging for industry to identify and assess reasonable, cost-effective and widely available solutions that could meet the standard set forth in the NOPR, in as much as the Commission is proposing to require owners and operators to develop and implement plans so that instability, uncontrolled separation, or cascading failures of the BPS, will not occur as a result of a GMD event, no matter how extraordinary. *See* NOPR at 23. Understanding the nature of the GMD threat and modeling of the potential impacts of GMDs caused by such a threat is by necessity the cornerstone of any effective mitigation strategy. Unfortunately these tools are still immature and not yet validated (*e.g.*, power flow models that incorporate the behavior of half-cycle saturated power transformers have not been validated with measurement data) and therefore are not ready for broad application by the industry. Hence, the Trade Associations are concerned that the NOPR appears to wrongly reflect the belief that GMD modeling tools are sufficiently refined and readily available to effectively mitigate the impacts of a severe GMD event.

In sum, the Trade Associations believe that without a strong consensus on the technical specification of a GMD event and confidence in the tools currently available for modeling the effects of GICs, the NOPR presents insufficient basis to conclude that there is an adequate technical foundation for a new or modified NERC Reliability Standard on

GMDs as proposed in the NOPR. For these reasons, a directive to NERC to develop mandatory standards under Section 215(d)(5) of the Federal Power Act ("FPA") is premature. NERC's GMDTF Phase 2, Recommendation 4 seeks to review the need to enhance NERC Reliability Standards.[7] The NERC GMDTF Phase 2 should be completed prior to any new or amended Reliability Standards being promulgated on this issue. To do otherwise would not serve the industry or the electric customers they serve well and could result in Commission mandates that may do more harm than good, because they would direct Registered Entities to take actions that could have unintended adverse impacts on reliable operation of the BPS.

The Trade Associations do support the Commission encouraging NERC to expedite completion of the work of the GMDTF and to submit NERC's recommendations for concrete GMD mitigation activities as soon as possible. The Commission should require NERC to make an informational filing within six months of an order in this proceeding, providing a status report on its work plans and activities. The Trade Associations stand ready as well to assist their members and other industry participants in efforts to catalogue and share current industry knowledge of GMD phenomena and best practices for the mitigation of GMD through operating procedures, GIC monitoring equipment, situational awareness and the design, testing and coordination of specific devices to mitigate GICs.

If the Commission finds it must direct NERC to develop a standard or standards to address the impact of GMDs on the BPS, the Trade Associations support the

[7] NERC GMD Task Force Phase 2.

Commission's stage one proposal to require NERC to file one or more standards which would require grid owners and operators to develop and implement operations procedures that would mitigate GMD effects.[8] The Trade Associations agree that the Commission should avoid directing prescriptive standards. At this stage, it would be inappropriate to require owners and operators of the BPS to engage in determining and implementing mitigation measures until greater consensus on GMDs can be achieved. The Trade Associations support the NOPR's proposal for stage one to include identification of facilities most at-risk from severe GMD events since this exercise is required to conduct meaningful ongoing assessments of the potential impact of GMDs on BPS equipment and on the BPS as a whole. However, as discussed below, NERC should not be performing these assessments and it should be recognized that such an effort is highly dependent on improved modeling of GICs, improvements to area and regional power flow modeling of GIC propagation, and benchmarking of such models against actual GICs.

In view of the unsettled state of the science analyzing the GMD phenomena, and uncertainty regarding the best methods for addressing it, as well as the lack of mature modeling tools, the Trade Associations urge the Commission to refrain from implementing its stage two proposal at this time. Ongoing studies of GMD phenomena and appropriate responses reveal a good deal of disagreement regarding the nature of the threat and the efficacy of various strategies for addressing it. Given this uncertainty, stakeholders cannot develop requirements to reasonably address a GMD disturbance. Thus, it will be difficult to arrive at a uniform procedure without a better understanding

[8] In this regard, the Commission should recognize that areas most likely to be affected by a GMD event already have such procedures in place.

of the nature of the risk and vulnerabilities presented by GMDs, particularly in areas otherwise believed to have little risk from such phenomena.[9] Nor is there any assurance that the strategies that have been studied to date will in fact guarantee there will be no system disruptions, as the proposed phase two rule appears to contemplate. For these reasons, the Trade Associations urge the Commission to coordinate closely with NERC and the industry as additional work on this issue is undertaken, and remain ready to take further affirmative steps when the nature of the threat and the efficacy of proposed solutions are better understood.[10] The Trade Associations in turn pledge that they will work with their members, subject matter experts and NERC to address these technical uncertainties on an expeditious basis.

Above all, the Trade Associations urge the Commission to exercise significant caution in this docket and guard against the possibility that directives to NERC could inadvertently create a cure that is worse than the potential GMD disease. In particular, "GIC blocking devices" have not yet been adequately studied or tested to determine their local area system impacts or failure modes, and therefore should not be relied upon at this time. Furthermore, any application of such devices without understanding their broader impact as part of the coordination of protection systems could potentially introduce new everyday reliability problems well beyond any benefit achieved through the mitigation of a severe GMD event with a very low likelihood of ever happening. Since the system-

[9] In turn, without a consensus on the nature of GMD events, the Commission would be unable to have a reasoned basis for approving requirements that would purport to avoid causing widespread cascading outages, uncontrolled separation, or system instability.

[10] GMDTF work is vital to informing the technical assessments of potential GMD events and addresses four important issues: (1) Improvement of tools for industry planners to develop GMD mitigation strategies; (2) Improvement of tools for system operators to manage GMD impacts; (3) Education and information exchanges between researchers and industry; and (4) review the need to enhance NERC Reliability Standards.

wide modeling tools are not ready and such modeling is critical to inform mitigation decisions, including the design scheme for the placement of equipment such as blocking devices, again, the Trade Associations strongly believe that a Commission directive for equipment assessments is premature.

Finally, the Trade Associations ask the Commission to consider the cost of mitigating the potential effects of GMDs and to allow for ISOs/RTOs to make tariff filings to provide for recovery of out-of-market costs incurred to comply with GMD Reliability Standards and GMD mitigation costs.[11] The NOPR's cost/benefit justification is questionable and the fact is that many generation facilities lack a mechanism for recovery of such extraordinary investments deemed to be in the national interest and would not be compensated by other market means.

IDENTITIES OF THE TRADE ASSOCIATIONS

APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power utilities provide over 15 percent of all kilowatt-hour sales of electricity to ultimate customers, and do business in every state except Hawaii. Collectively, public power systems serve over 46 million customers. Three hundred twenty-eight public power utilities are now included on the NERC compliance registry and are thus directly subject to NERC Reliability Standards, pursuant to FPA Section 215. One hundred and twelve public power utilities are designated as Transmission Owners.

[11] Note that APPA and NRECA do not join in the section of these comments addressing recovery of out-of-market costs.

EEI is the association of United States investor-owned electric utilities and industry associates worldwide. Its U.S. members serve almost 95 percent of all customers served by the shareholder-owned segment of the U.S. industry, about 70 percent of all electricity customers, and generate about 70 percent of the electricity delivered in the U.S. EEI frequently represents its U.S. members before Federal agencies, courts and Congress in matters of common concern, and has filed comments before the Commission in various proceedings affecting the interests of its members. EEI's members have a strong interest in efficient grid operations, which will go far to ensure reliability and efficiency of BPS equipment.

LPPC represents 25 of the largest state and municipal-owned utilities in the nation. Together, LPPC’s members represent 90% of the transmission investment owned by non-federal public power entities.

NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives, including 66 generation and transmission cooperatives that supply wholesale power to their distribution cooperative-owner members.

BACKGROUND

Given the concern that a solar storms and other high-impact, low frequency (HILF”) events may have the ability to disrupt the normal operations of the power grid, in July of 2009, NERC and the U.S. Department of Energy (“DOE”) partnered on an effort to address HILF risks to the electric grid. In June 2010, this effort resulted in the issuance of a joint NERC/DOE report titled: High Impact, Low Frequency Event Risk to the Bulk Power System of North America[12] ("NERC/DOE HILF Report") that included GMD risks.[13] The NERC/DOE HILF Report recommended, among other things, that NERC, working with its stakeholders, the DOE and appropriate government authorities in Canada create a task force of industry, equipment manufacturers, and risk experts to evaluate and prioritize mitigation and restoration options for GMD events. The NERC/DOE HILF Report provided the basis for NERC to form the GMDTF to study GMDs and produce an assessment that focused on the effects of GMDs on the BPS.

Since the formation of the GMDTF, a number of studies that have concluded that GMD events can have an adverse impact on the reliable operation of the BPS. However, these studies differ significantly on the nature of the risks that result from the introduction of GICs. For example, the ORNL/Metatech Report stated that GMD events can develop quickly over large geographic footprints, having the capability to produce geographically large outages and significant damage to BPS equipment.[14] The ORNL/Metatech Report assessed the effects of a "1-in-100 year" geomagnetic storm on the modern BPS and concluded that such an event could put hundreds of BPS transformers at risk for failure or permanent damage. Estimates prepared by the National Research Council of the National Academies concluded that these events have the potential to cause wide-spread, long-term losses with economic costs to the United States estimated at $1-2 trillion and a recovery time of four to ten years.[15]

---

[12] *See* NERC/DOE Report: *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* (June 2010). Available at: http://www.nerc.com/files/HILF.pdf.

[13] *See id*.

[14] *See* Meta-R-319, at 1-31.

[15] *See* NAS Workshop Report: *National Research Council of the National Academies Severe Space Weather Events,*

In contrast, the NERC Interim GMD Report that was issued in February 2012 concluded, that the worst-case scenario for an extreme GMD event is "voltage instability and subsequent voltage collapse." [16] In addition, the Pacific Northwest National Laboratory ("PNNL") report on ("PNNL Report") the impact of a severe GIC event on the Western Interconnection said that the impact of such a storm on the electric power deliver system could be significant, but based on the results of the study, PNNL found no reason to think it would be catastrophic in the Western region.[17]

The seriousness of the risk posed by GMDs to the reliable operation of the BPS was debated at a Technical Conference held by the Commission on April 30, 2012. At the Technical Conference, several panelists indicated that severe GMD events could potentially compromise the reliable operation of the BPS, with some noting as an example the GMD-induced disruption of the Hydro-Québec grid in 1989 (other panelists, however, disagreed with his conclusion). At the Technical Conference, panelists stated that the current 11-year solar activity cycle is expected to hit its maximum activity in 2013 and large solar events often occur within four years of such a cycle maximum.

On October 18, 2012, in the above-referenced docket, the Commission issued its NOPR. The Commission proposes to direct NERC to create and submit Reliability Standards that address and mitigate the effects of GMDs on the BPS. While strong

---

Understanding Societal and Economic Impacts at pp. 4 and 79 (2008). Available at: http://www.nap.edu/catalog/12507.html. Note, this paper indicates that these estimates were derived by Metatech Corporation, presented by J. Kappenman at the space weather workshop, May 22, 2008.

[16] *See* NERC Special Reliability Assessment Interim Report: *Effects of Geomagnetic Disturbances on the Bulk Power System* at 69 (Feb. 2012) ("GMDTF Interim Report").

[17] *See* PNNL-21033. The Trade Associations believe that the widely varying conclusions in the body of science demonstrate that much more work is necessary to better assess the risks of GMD

GMDs are extremely rare events, the NOPR takes the view that their potential impact on the reliable operation of the BPS (*e.g.*, widespread blackouts) requires Commission action under section 215(d)(5) of the FPA. Additionally, the NOPR asserts that currently GMD vulnerabilities are not adequately addressed in the Reliability Standards and this constitutes a reliability gap because GMD events can cause the BPS to collapse suddenly and can potentially damage the BPS.

Specifically, the NOPR proposes to direct NERC to act in two stages: (a) in stage one, the Commission would direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operations of the BPS; and (b) in stage two, the Commission would direct NERC to file, within six months of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the BPS to conduct initial and on-going assessments of the potential impacts of GMDs on BPS equipment and the BPS as a whole.[18] Based on those assessments, the Reliability Standards would further require owners and operators of the BPS to develop and implement a plan, subject to certain requirements, so that instability, uncontrolled separation, or cascading failure of the BPS, caused by damage to critical or vulnerable BPS equipment or otherwise, will not occur as a result of a GMD.

[18] The NOPR states that this second stage would be implemented in phases, focusing first on the most critical BPS assets.

COMMENTS

I. The Trade Associations take the risk of GMDs seriously and the electric industry has worked diligently to better understand their effects and minimize their impacts, but the tools necessary to assess the risks of GMDs have not yet been fully developed.

The Trade Associations take very seriously all potential threats and vulnerabilities that could affect the reliability of the electric system, including GMDs. The electric industry has recognized that understanding the effects of GMDs on the BPS and the ability of the industry to mitigate their effects are important to managing system reliability. As a consequence, there has been a broad array of activities underway for several years to better understand and address this issue at EPRI, NASA, NOAA, and the CCMC Industry Collaboration. *See* Appendix A. Additionally, IEEE and the CIGRE have commissioned working groups to address GMD impacts on the grid. Although progress has been made, the industry is not yet ready to say with certainty where reasonable methods of mitigation are necessary or in what manner they should be applied because many industry initiatives have not been fully refined. Hence, the Trade Associations are concerned that the Commission may believe that necessary tools and refined solutions are readily available to effectively assess and mitigate the impacts of GMD events, when this is not the case.

The Commission should understand that the modeling tools necessary to assess GMD and GIC impacts are highly immature. Only recently have some commercial products become available, but even these are not yet adequately developed for broad application. Moreover, EPRI, through the GMD Project, has developed an open source tool that is now available for general use but it also needs substantial work before it can be relied upon to produce reliable results that have been verified through field measurements. Furthermore, the open source tool lacks some of the desirable features now being provided by the commercial solutions.

Similarly, while utilities are expanding their GIC monitoring capabilities, this is often being done without the necessary predictive modeling and as a result this data does not fully inform the risks of elevated GICs to a level of accuracy that is desired or achievable in the future. Therefore, given the complexities of how GICs are manifested, the Trade Associations does not believe that these efforts can be fully depended upon to predict the overall impacts of postulated GMD events until the necessary modeling tools have been completely developed and validated.[19] Once all of the necessary tools have been developed and validated and company networks have been modeled, GIC monitoring may prove to be an extremely useful tool in validating the planning models, in addition to its operational benefits.

The Commission should also understand that companies are taking all reasonable actions to protect their assets, including GIC impact assessments of power transformers.[20] However, this data can only provide marginal usefulness until there is a better understanding of projected GIC levels through system modeling. Although this information provides an incomplete picture of transformer risk and cannot be fully useful

[19] The Trade Associations understand that these modeling tools have not yet been validated against values obtained from field measurements.

[20] Transformer assessments data provided by ABB; GIC Studies performed by ABB on Power Transformers for Utilities worldwide; PowerPoint slide presentation dated June 9, 2011. These assessments are conducted by industry experts in the design of power transformers in order to evaluate GIC susceptibility. For each category of transformer, assessments are made to determine the potential for core saturation and winding damage due to component overheating. More detailed assessments are conducted on transformer categories classified as susceptible to core saturation as well as those susceptible to overheating caused by GICs. Asset owners receive these analyses when they take receipt of new equipment.

without necessary GIC system planning results, it does provide some information as to which assets may be at risk and may help to educate and inform system operations personnel of prudent steps they can take to better protect system assets during a severe GMD event. Nevertheless, the full impact and value of this knowledge is tied to effective GIC modeling through effective system planning tools. More specifically, GIC transformer withstand capability can only be effectively assessed though an understanding of GIC levels at specific geographical locations given their position in the network, system operating conditions and the magnitude of a given GMD.

Situational awareness, (*i.e.*, the methods and processes for alerting the industry to a pending GMD event) is improving but considerable R&D work remains before it can deliver the advanced notifications needed by the electric industry. The scientific understanding of extreme space weather events and the physics of solar-terrestrial phenomena has experienced a measured improvement over the past decade, but much work remains before satellite data received from NASA and NOAA can be effectively integrated into industry systems that adequately inform system operators in ways that effectively guide industry operational procedures. Until these solutions are fully developed, the industry will continue to refine and collaborate with groups such as the CCMC.[21] The Trade Associations note that improvements are now less reaction-based and beginning to enter a new era of proactive situational information through both *in situ* and remote observations and physics-based large-scale simulations of the space environment.

[21] The CCMC is a multi-agency (governmental) partnership. The CCMC provides, to the international research community, access to modern space science simulations. In addition, the CCMC supports the transition to space weather operations of modern space research models. http://ccmc.gsfc.nasa.gov/about.php.

At the present time, the industry is capable of effectively managing risk through operations procedures due to the currently available space weather forecasts and warning systems which allow for event lead-time of 1-2 days and more refined short lead-time notices of 30-60 minutes bases on current satellite data from the Advanced Composition Explorer ("ACE") spacecraft.[22] Operational Procedures continue to be the only effective solution even though they remain imperfect due to the state-of-the-art of supporting technologies. It is also important to note that PJM, ISO-NE, NYISO, and MISO all have developed communications and mitigation procedures for this type of vulnerability.

II. The Trade Associations support the efforts and findings of the NERC GMD Task Force and believe its work presents a foundation for effective mitigation of GMD risks.

In 2010, NERC established the GMDTF to address the implication of severe GMD events. This included assessment of GMD studies developed after the 1989 GMD storm, performing analysis of GMD scenarios as set forth in the NERC/DOE HILF report, and reporting on the impacts that a GMD event would have on the BPS. GMDTF was also charged with focusing on enhancing and improving existing prevention, mitigation and system restoration approaches.

The Trade Associations cannot emphasize enough that the GMDTF represents an open and inclusive process, leveraging a large body of technical expertise with decades of experience. For example, the GMDTF is a joint task force reporting to the NERC Planning Committee and Operating Committee, with participation by the Critical Infrastructure Protection Committee. The GMDTF includes NERC member entities,

[22] The ACE is an Explorer mission that was managed by the Office of Space Science Mission and Payload Development Division of the National Aeronautics and Space Administration. The ACE satellite data is used to by the Solar Shield project to generate Alert for the electric utility industry. *See* http://www.swpc.noaa.gov/ace/ACE.

equipment suppliers and manufacturers, GMD experts, government agencies (Federal, Provincial, and State), and NERC staff. Moreover, it is also significant that the GMDTF work is peer reviewed and collaboratively developed including input from non-NERC members. Specifically, the results of the GMDTF efforts are reviewed periodically by the leadership of the technical committees, in coordination with the Electricity Sub-Sector Coordinating Council. The Trade Associations underscore the importance of an organized effort that includes a broad range of experienced technical experts who are dedicated to identifying technical challenges, conducting thorough analyses, and seeking to address those challenges with reasonable and integrated solutions.

A. The Trade Associations strongly agree with the GMD Task Force Interim Report Recommendations

The GMDTF Interim Report[23] was issued in February 2012 and made the following high level recommendations:

- Improve tools for industry planners to develop GMD mitigation strategies
- Improve tools for system operators to manage GMD impacts
- Develop education and information exchange between researchers and industry
- Review the need for enhanced NERC Reliability Standards

For the purposes of considering the proposals made by the Commission in this NOPR, the Trade Associations believe that the GMDTF Interim Report contains several critical conclusions to which the Commission has not given due weight. First, the lack of sufficient reactive power support was a primary contributor of the 1989 Hydro-Quebec

[23] *See* NERC GMD Taskforce Interim Report at 85.

GMD induced blackout.[24] This finding is consistent with the findings of the PNNL Report.[25] Second, a severe GMD would not result in the failure of large numbers of EHV transformers.[26] Again, the PNNL Report arrived at similar conclusions.[27] Third, the GMDTF Interim Report also concluded that "the most significant issue for system operators to overcome from a strong GMD event would be to maintain voltage stability, as transformers absorb high levels of reactive power while protection and control systems may trip supportive reactive equipment due to harmonic distortion from signals."[28] Additionally, the GMDTF Interim Report concluded that transformers of certain older designs along with those in poor condition are most vulnerable to the effects of GMD.[29] Finally, the industry needs "technical tools to model GIC flows and subsequent reactive power losses to develop mitigating solutions."[30]

The Trade Associations strongly agree with the GMDTF Interim Report and believes that the report's recommendations align well with the current state of the art relative to the GMD phenomenon. Any effective response to a GMD event must ultimately rest on the industry's ability to effectively model GIC flows and reactive power losses.

The GMDTF has now begun the second phase of its work. Since the work plan intends to address several issues that directly relate to GMD modeling and mitigation

[24] *See id*. at 85.

[25] *See* PNNL-21033, at 15-17.

[26] *See* GMDTF Interim Report, at 85.

[27] *See* PNNL-21033, at 17.

[28] *See* GMDTF Interim Report, at 85.

[29] *Id.* at 85-86. Such technical tools need to be validated with measurement data.

[30] *Id*. at 86.

issues, the Trade Associations recommend that the Commission direct NERC to make an informational filing within six months of the final rule in this docket, seeking a status report on GMDTF work plans and activities. The informational filing could identify priority activities and timelines, and tasks that might be accelerated as well as activities that can be deferred or eliminated.

III. The Trade Associations cannot support the analyses and findings of the ORNL/Metatech Report (Meta-R-319, etc.) because they are based on proprietary tools and methodologies, lack peer review, and contain numerous technical flaws and omissions that color the credibility of the report.

Although the NOPR states the Commission proposes to take action on the basis of certain government-sponsored studies and NERC studies that are characterized as establishing that GMD events can have adverse, wide-area impact on the reliable operation of the BPS, [31] the Commission's primary foundation for its proposal appears to be the ORNL/Metatech Report. The Trade Associations have multiple concerns with this report.

In contrast to the GMDTF and its open and transparent process, the ORNL/Metatech Report was developed without the benefit of a rigorous peer review, a basic requirement for scientific inquiry involving complex technical subject matters. Subject matter experts cannot verify the methods, processes, equations, or data, making the report a "black box." Moreover, software used to support analyses in the ORNL/Metatech Report remains largely unavailable for technical review, making it nearly impossible to verify or refute the findings.[32]

[31] NOPR at P 2.

[32] Again, this software may be available to equipment manufacturers, but is not available directly to the member

The Trade Associations believe that relationships between numerous technical conclusions that are revealed in the ORNL/Metatech Report need far more testing and validation before the Commission can reliably use such analyses as the basis for action under Section 215(d)(5). As previously stated, the Trade Associations understands that the PNNL study of the Western Interconnection arrived at very different conclusions than the ORNL/Metatech Report.[33] Of those conclusions found in the PNNL Report that are most significant include the following:

> Without doubt, a major geomagnetic storm will again hit earth. It is not a matter of *if*, but *when*. The impact of such a storm on the electric power delivery system may be significant, but based on the results of our study, we found no reason to think it would be catastrophic.[34]
>
> GIC currents are blocked by series capacitors, and the transformers on lines that do not have series capacitors can be well protected by relaying schemes using technologies that already exist.[35]

B. The ORNL/Metatech Report contains numerous basic technical flaws that diminish the credibility of its findings.

The Trade Associations identified three key technical flaws when evaluating the ORNL/Metatech Report that are key in both the understanding of the level of risk and the urgency with which the industry should respond to the effects of a severe GMD event. Specifically, these flaws call into question the credibility of the severe geomagnetic storm scenario, the voltage collapse scenario due to increased reactive power demand, and transformer damage due to increased hot-spot heating. These flaws are basic analytical problems that cause the Trade Associations to conclude that the Commission has wrongly

companies of the Trade Associations.

[33] *See* PNNL-21033.

[34] *See* PNNL-21033, at P 21.

[35] *See Id*.

placed its confidence in this work as a basis for the NOPR's proposals.

First, without a firm scientific basis for the representation of what constitutes a "severe geomagnetic storm," credible studies cannot be performed, let alone effective engineering responses. The ORNL/Metatech Report contains a depiction of such a scenario that the Trade Associations believe lacks scientific credibility. Specifically, the Trade Associations respectfully submit that one cannot define the broad impacts of a storm scenario utilizing peak historic measures with any degree of accuracy. To do so seriously exaggerates what is known in the current body of science. The Trade Associations also find a number of inaccuracies and inappropriate technical leaps relative to storm event frequency that suggest levels of accuracy but contain no information that could reasonably suggest that the necessary rigorous statistical analysis needed to support the claims had been performed. The Trade Associations are also concerned that separate and isolated events have been linked together in order to provide justification for extreme GMD storm levels (*i.e.*, "disturbance intensity approached a level of ~5000 nT/min"), while providing no rigorous statistical analysis to justify such claims. *See* Appendix B.

Second, the Trade Associations believe that the basis for the voltage collapse scenario as contained in the ORNL/Metatech Report lacks credibility because the Trade Associations can find no indication that power flow simulations were conducted to support its conclusions. Without such studies, at best, any conclusions can only be speculation. The Trade Associations also believe some of the methods used to calculate reactive power, although based on earlier work, are now considered obsolete because they yield erroneous results that overestimate reactive losses by 60% or more. The Trade Associations also note that the ORNL/Metatech Report assumes nominal system voltage in its calculations while during an actual GMD event, system voltage will be depressed, which also reduces reactive power losses, rendering the use of nominal system voltage a basic analytical error that significantly affects the conclusions of the planning study. Finally, the report assumes a linear relationship between GIC and reactive power demand (Q) for all transformer types, which the Trade Associations believe is an overgeneralization that further diminishes the paper's conclusions. See Appendix B.

Third, the Trade Associations believe the methods used to assess transformer damage for a GMD event to have been arbitrarily selected and devoid of any theoretical foundation or basis. Specifically, the assumption of 90 Amps per phase GIC loading was used to determine transformer failure. This makes for dramatic and potentially frightening predictions, however, the Trade Associations can find no credible engineering basis in the ORNL/Metatech Report for this extreme assumption.

The Trade Associations also understand that the deficiencies in the methods and assumptions used to estimate the risks associated with transformer heating in the ORNL/Metatech Report are inconsistent with actual heating time constants used throughout the industry for power transformer windings and metallic parts of on the order of 3-5 minutes, which further translates to a 15-25 minute lag time before winding and metallic hotspots can reach their steady-state values. The Trade Associations provide greater detail on these deficiencies in Appendix B of these Comments.

C. The ORNL/Metatech Report does not fully disclose information on key GIC events, which serve to inflate the perception of wide spread equipment damage due to GICs based on historical events.

The Trade Associations find some aspects of the ORNL/Metatech Report are missing key facts that provide a more unbiased view of those events. For example, with respect to the Hydro Quebec Blackout, Section 2 of the ORNL/Metatech Report appropriately describes the events leading to the two transformer failures that were due to overvoltage resulting from the network collapse and not a direct result of GICs. However, in Section 4, the event is again referenced, however, this section of the report seeks to make the case that power transformers are at risk of damage due to the heating effects of resulting in GICs heating, which was not the root cause of these failures. Similarly, the PSEG/Salem generator step up transformer failure was used to point to the potential risks to industry transformers. While this transformer failed as a result of GIC heating, its design and location made it particularly vulnerable to these effects. The Trade Associations do not believe this transformer accurately represents the broad risks for the industry. Finally, the Trade Associations believe that descriptions of the transformer failures in the Eskom, South Africa event have lacked some pertinent information which may further inform the nature of those failures and the impacts of low level GICs.

A more detailed description of these events can be found in Appendix B.

IV. Although the Commission has authority pursuant to Section 215(d)(5) of the FPA to direct NERC to develop a mandatory reliability standard, it should not adopt the NOPR's proposals.

Section 215 of the Federal Power Act sets out the Commission's authority with regard to Reliability Standards, and defines a "reliability standard" as a requirement approved by the Commission "to provide for reliable operation of the bulk-power system." 16 U.S.C. §§ 824o(b) and (a)(3). The statute defines "reliable operation" to mean "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." 16 U.S.C. § 824o(a)(4).

The NOPR asserts that the Commission exercised its authority to order the actions proposed in the NOPR under Section 215 is justified on the basis of certain government-sponsored studies and NERC studies that establish GMD events can have adverse, wide-area impacts on the reliable operation of the BPS. *See* NOPR at P 2. For example, the NOPR states that although strong GMDs are infrequent events, their potential impact requires Commission action. *See* NOPR at P 3. The NOPR does acknowledges that there is not unanimity among experts with respect to BPS risk as a result of a GMD event, but it asserts that Commission action is also warranted "by the lesser consequence of a projected widespread blackout without long-term, significant damage" to the BPS. *See* NOPR at 5. Moreover, with regard to NERC Reliability Standard IRO-005-3a (Reliability Coordination – Current Day Operations), Requirement R3, which discusses GMDs and requires Reliability Coordinators to make Transmission Operators and Balancing Authorities aware of GMD forecast information and assist as needed in the development of response plans, the Commission's view is that "GMD vulnerabilities are not adequately addressed in the Reliability Standards" ostensibly because NERC Reliability Standards do not require steps for mitigating the effects of GMD events. Accordingly, the NOPR concludes that there is a gap in the NERC Reliability Standards that justifies use of its authority pursuant to Section 215(d)(5).[36]

The Trade Associations understand the Commission is afforded considerable discretion to interpret this provision of the FPA as a matter of first impression, but as set forth in these Comments the NOPR does not adequately explain the Commission's reasoning in light of the issues attendant to the studies it relies upon for support.

Holding aside the substantial questions about the underlying studies that the NOPR asserts justify Commission action with respect to the nature of GMD events and the potential impacts of such events, the Trade Associations acknowledge that NERC Reliability Standards do not expressly require steps for mitigating the effects of GMD events. Nevertheless, this does not suggest that the Commission should exercise its authority under the statute by adopting the NOPR's proposal without modification. While FERC has authority under Section 215(d)(5) to direct the ERO to develop a mandatory standard on a specific matter, the specific matter that is the subject of this NOPR, GIC levels caused by strong GMD events, does not have a strong scientific or technical consensus upon which to develop standards. Especially with regard to the proposal to develop a mandatory standard for the assessment of 'critical' transformers and other equipment, and to conduct system-wide assessments on the impacts of a historic GMD event, defining a technically sound specification for 'critical' would rest on guesswork. In addition, the models for assessing system-wide impacts do not even exist. Accordingly, the Trade Associations believe it would be premature for the Commission to adopt the specific proposal presented in the NOPR without modification, as discussed

[36] *See* NOPR at P 4.

below.

A. If the Commission finds that a Reliability Standard or standards are necessary, the Trade Associations support the NOPR's proposal to direct the development of Reliability Standard requiring operational procedures to mitigate the effects of potential GMD events.

The NOPR proposes that during the first stage NERC would develop standards requiring electric companies to develop and implement procedures to mitigate the effects of GMD events. *See* NOPR at PP 18-19. These standards should be coordinated among all entities across the grid. These standards would be filed with the Commission within 90 days of the effective date of a final rule in this proceeding. In addition to developing Reliability Standards that require operational procedures during the first stage, the Commission also proposes for NERC to identify facilities most at risk from severe GMD events. *See* NOPR at P 22.

With respect to the proposal for NERC to file one or more Reliability Standards requiring owners and operators to develop and implement operational procedures, the Trade Associations note that the NOPR recognizes that areas most likely to be affected by a GMD event already have sufficient procedures in place. However, these procedures are based on each system's specific experiences with and assessment of future risks of GMD impacts on system operations. It will be a much greater challenge to define operational procedures to mitigate a GMD threat, as proposed in the NOPR, when there is no consensus on the nature of this risk, as discussed above. Similarly, it is very important for the Commission to appreciate that it will be unrealistic to meet the expectation of a uniform procedure because the magnitude of the GIC impacts and the specific vulnerabilities faced by each system differ so widely across North America.

Even with a limited requirement, the Trade Associations do not believe that the NOPR's proposed deadline for NERC to file this standard or standards within 90 days of the effective date of the final rule is realistic. *See* NOPR at P 19. In a similar vein, the Commission should not propose to direct a specific implementation schedule for the proposed Reliability Standards, such as the 90-day target that the Commission encourages. *See* NOPR at P 21.

Such deadlines are not consistent with the Commission-approved NERC Rules of Procedure, in particular Appendix 3A and the Expedited Reliability Standards Development Process. The Commission's time periods contravene Section 215 of the FPA when it denies the industry and the ERO the opportunity to develop the proposed Reliability Standards and thereby not give due weight to the technical expertise of the industry. The Commission's proposed deadlines also violate the due process rights of the industry. Under the Commission's proposal, those who would become subject to penalty for failure to comply are denied the opportunity to develop any standards in a manner that is consistent with the Commission-approved requirements set forth in the NERC Rules of Procedure. Moreover, the NOPR fails to justify departure from the approved and established standards development process. To the extent that it is necessary to develop the standards proposed by the Commission, the Trade Association's preliminary view is that it may be realistic to expect owners and operators to implement the required operational procedures six months after final Commission approval of the stage one Reliability Standards, provided that the Commission establishes a realistic target date for NERC development and approval of the stage one operational procedure standards.

The Trade Associations support the Commission's proposal that NERC provide periodic reports assessing the effectiveness of operational procedures in mitigating the effects of GMD events and make recommendation to owners and operators that they incorporate lessons-learned and research findings. *See* NOPR P 21. In this regard, the Trade Associations suggest that NERC should make such reports based on the timing of the solar cycle. The Trade Associations caution that depending on the levels of GIC experienced, there may be minimal data to assess the effectiveness of these operational procedures.

With respect to the proposal for NERC to identify facilities most at-risk from severe GMD events and to conduct wide-area GMD vulnerability assessments simultaneously with the development and implementation of the first stage GMD Reliability Standards, the Trade Associations believe that this assessment of the potential impact of GMDs on BPS equipment and on the BPS as whole is necessary. *See* NOPR at P 22. However, the Trade Associations do not agree that NERC should be directed to actually perform these assessments and they should be performed after the necessary tools and methodologies have been developed and validated. This type of activity is not within NERC's role or expertise. The Trade Associations believe that system wide assessments are appropriately conducted by Planning Authorities, and that equipment assessments should be done by owners and operators of the BPS.[37] More fundamentally, the Commission must understand that there is limited benefit from such assessments when there is no consensus on the nature and risks of GMDs. Thus, it will be very difficult to develop an assessment lacking such critical criteria. Moreover, without

[37] If FERC does determine that NERC should conduct these assessments, then it should specify that the NERC Planning Committee is tasked with this work in order to ensure that stakeholder expertise is leveraged.

criteria and mature modeling tools, it will be difficult to determine what constitutes "critical transformers."[38] Furthermore, preparing an assessment in advance of stage two will limit utilities to characterizing their existing asset inventory as opposed to performing vulnerability assessments.

Thus, the Trade Associations recommend that the Commission task NERC, working with the industry through the GMDTF and other committees and vendors, with developing agreed-upon baseline criteria and modeling tools that can be applied by Planning Authorities and asset owners that are at risk of significant GICs within their respective BES areas. This effort should take place after the development of any stage one standards for operating procedures.

B. If the Commission finds that a Reliability Standard or standards are necessary, it should modify the NOPR's proposal to direct the development of Reliability Standards to require the assessment of the impact of GMDs on BPS equipment.

In the NOPR, the Commission proposes that NERC conduct an "initial action" systemwide assessment, as well as an assessment of "critical" or "vulnerable" transformers and other equipment. *See* NOPR at P. 22. The NOPR also proposes that the Commission direct NERC to develop a mandatory standard which would require owners and operators to conduct periodic assessments of equipment, and for mitigation plans that describe actions to resolve problems identified in these assessments.[39] Based on those assessments, the Reliability Standards would then require owners and operators to develop and implement a plan "so that instability, uncontrolled separation, or cascading

---

[38] *See* NOPR at 22. Furthermore, the need to develop a vulnerability assessment tool was identified in the NERC Interim GMD Report as an industry recommendation. *See* GMDTF Interim Report at p. 89.

[39] *See* NOPR at PP 24-25. The NOPR cites the ORNL/Metatech Report and NERC/DOE HILF Report as the basis for the proposal.

failure of the BPS, caused by damage to critical or vulnerable BPS equipment, or otherwise, will not occur as a result of a GMD." *Id.* at P 23. Finally, the Commission proposes a set of criteria that might inform the content of this standard. *Id.* at PP 27-32.

The Trade Associations do not support this proposed directive for several reasons. As previously stated in these Comments, the reliability basis for conducting these assessments is not strongly rooted in a robust body of scientific work, the ORNL/Metatech Report in particular is flawed, and the various modeling tools that would support the effort are not yet in place.

If the Commission moves ahead with the NOPR's stage two proposal, the Trade Associations request that the Commission should not direct NERC to create a mandatory standard that contains uniform evaluation criteria.[40] A uniform set of GIC values would not be realistic for all owners and operators, due to the widely varying geology and geomagnetic latitudes within which the BPS is planned and operated. BPS topology, power flows, geology, the orientation of transmission lines, and the design characteristics and ratings of transformers all vary widely. Moreover, the proposed uniform criteria could conflict with the proposal that owners and operators conduct studies under varying intensities of GICs. Instead, the Commission should allow NERC to develop a standard that recognizes the broad diversity of the industry. Hence, as an alternative to directing NERC to develop such a Reliability Standard within six months of the effective date of

[40] *See* NOPR at P 28. The Trade Associations are not clear on whether the Commission means a uniform GMD event scenario, or that all owners and operators must assess their equipment on the basis of identical assumptions. The former is problematic because there is no consensus storm scenario and GMDTF is working on this in phase two. The latter is problematic because of wide differences in geology and latitude, two basic ingredients for GIC current expectations.

Final Rule in this proceeding,[41] the Commission should have the NERC GMDTF accelerate its activities for this work as suggested above.

The Trade Associations similarly suggest that if the Commission requires stage two assessments that the Final Rule should avoid raising a debate on how to define the term "critical." The NOPR proposes that the Reliability Standards would require plans so that instability, uncontrolled separation, or cascading failures of the BPS "caused by damage to critical" BPS equipment or otherwise.[42] Again, the Commission should avoid prescription in light of the widely varying geology and latitudes within which the BPS is planned and operated. Accordingly, the Trade Associations agree with the NOPR's statement that the owners and operators of the BPS "are the most familiar with the equipment and system configuration,"[43] and suggest that avoiding the use of the term "critical" may reduce delays, and disputes.

The Commission should recognize that the potential array of mitigation activities can introduce new reliability problems. The NOPR states that the Commission does not propose a particular solution in the second stage Reliability Standards, but also states that the Commission expects that some assessments will demonstrate that automatic blocking is necessary in some instances. *See* NOPR at P 34. In the NOPR, the Commission seeks comment on "GIC blocking devices," saying that they can prevent GIC from flowing into transformers and causing damage. *See* NOPR at PP 34-36.

---

[41] *See* NOPR at P 25.

[42] *See* NOPR at P 26 (offering guidance on assessments of BPS vulnerability to GMDs and potential measures for automatically protecting "critical" or vulnerable components). *See* NOPR at P 22. The NOPR also uses the term "critical" with respect to evaluating "critical transformers" pursuant to initial actions in stage one.

[43] *See* NOPR at P 18.

The Trade Associations are not aware that the industry has adequately studied and tested devices that are intended solely to block GICs. Transmission Owners have installed a variety of devices such as series capacitors and static var compensators to support BPS voltage, increase transfer capabilities and ensure reliable operations under normal and abnormal system conditions. These devices may have the corollary benefit of reducing vulnerability to GICs. These devices have also been extensively tested and modeled for their specific impacts and facility limits before they are installed and placed into operation. Transmission Owners are extremely wary of installing any device that has not been fully studied, because the consequences can be severe: cascading, instability and uncontrolled separation and damage to other equipment. For example, it is possible that a GIC blocking device could cause inadvertent relay operations. Any directive to develop a standard to require equipment assessments must not be developed until the industry has verified that such devices are proven to be reliable. While Trade Associations understand that the NOPR states that the Commission does not propose to require any given solution, it is important to realize that these devices are being evaluated by the GMDTF (Team 3) that includes manufactures of such devices and the EPRI GMD Project. Allowing for this body of expertise to carefully study and discuss, and reach an informed consensus opinion on the application of neutral blocking devices is paramount to maintaining the reliability of the BPS.

More importantly, any determination of need for mitigating a problem must be based on a realistic characterization of the GIC levels likely to be experienced at any site. As addressed throughout these Comments, the body of science simply does not support a strong consensus on the nature of the threat. The studies cited by the Commission in the

NOPR are not reliable. Again, the NERC GMDTF in its phase two work plans to address these important threshold issues.

In sum, the Commission should not require the NERC to identify in the proposed Reliability Standards what would constitute appropriate automatic blocking measures, rather, it should require companies to develop effective methods of mitigation based on their knowledge and expertise of their own individual systems.

C. The Commission needs to consider the costs of mitigating potential effects of GMD events.

As a matter of good public policy, there needs to be some reasonable limits with respect to the costs involved in mitigating the effects of GMD events pursuant to a NERC Reliability Standard. The Trade Associations appreciate that the NOPR recognizes that there "could be substantial costs associated with some measures to protect against damage to the BPS,"[44] but the NOPR presents no reliable cost benchmarks to guide these investment decisions. *See* NOPR at P 7. Instead, the NOPR's cost-benefit analysis solely rests upon "[e]stimates prepared by the National Research Council of the National Academies [that] concluded … economic costs to the United States estimated at $1-2 trillion and a recovery time of four to ten years."[45]

The Trade Associations believe this report does not provide any support for the NOPR's conclusion of a favorable cost/benefit ratio for its proposal. The NOPR does not acknowledge that the National Research Council report is not an actual report, but is

[44] *See* NOPR at P 7.

[45] *See* NOPR at P 5 citing to the NAS Workshop Report: *National Research Council of the National Academies Severe Space Weather Events, Understanding Societal and Economic Impacts* at pp. 4 and 79 (2008). Available at: http://www.nap.edu/catalog/12507.html. Note, this paper indicates that these estimates were derived by Metatech Corporation, presented by J. Kappenman at the space weather workshop, May 22, 2008.

instead only a summary of a workshop held in 2008. Importantly, the National Research Council did not prepare the cited estimate and conducted no analytical research whatsoever. This cost estimate is based on the comments from a single speaker at the workshop for which there is no support in the National Research Council summary report. The Trade Associations do not believe this "report" provides the Commission with any useful information or realistic substantiation of its cost claims. Coupling the weaknesses embedded in the ORNL/Metatech Report with this NRC report leaves the Commission with a speculative case for its proposal, at best.

The Trade Associations are unable to locate the analysis underlying this estimate, however for the purposes of comparison observe that the entire shareholder-owned segment of the electric industry owns or operates approximately $700 billion in net plant, property, and equipment.[46] To provide some further context for this estimate, the most expensive natural disaster to occur in the last hundred years was the earthquake and tsunami that hit Japan on March 11, 2011. Estimates of the cost of this natural disaster range from $200 to $300 billion dollars.[47] Thus, it appears that the estimate cited by the Commission would be a scenario that would be six to ten times worse than the worst event to occur in the last hundred years. Furthermore, importantly, utilities plan for natural disasters and are able to rebuild the electric grid in the aftermath (*e.g.*, Hurricane Katrina). For example, nearly two thirds of the transmission and distribution system of

---

[46] *See* Edison Electric 2011 Financial Review at 16.
http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FinancialReview.pdf

[47] *See* Japan Damage Cost: $300 Billion; A. Greil, S. Oster, S. Ng, Wall Street Journal, March 22, 2011 http://online.wsj.com/article/SB10001424052748703858404576214271676234818.html

Mississippi Power was damaged or destroyed in the Hurricane Katrina.[48] Despite this extensive destruction, service was restored to every customer within twelve days. Thus this estimate also does not appear to adequately consider the ability of the industry to work together to plan and quickly rebuild the electrical grid. Accordingly, this estimate of trillions of dollars of damage appears extremely aggressive.

The Trade Associations believe it would be prudent for active cost-benefit studies to be performed in order to determine whether particular mitigation measures present costs that are commensurate with expected benefits. However, the Trade Associations do not agree that the Commission may properly rely upon such rough estimates of societal costs such as those referred to in the NOPR to justify issuing its proposed rule. *See* NOPR at P 7. The Trade Associations do believe that any Reliability Standard developed in this proceeding should include a requirement to demonstrate that mitigation measures are cost-effective.

All outages cannot be eliminated. Cost-effectiveness must consider the point at which the investment of additional resources reaches the point of diminishing returns in terms of achieving additional reliability. If a historically severe GMD event is viewed in ways similar to other severe natural events that can affect the electric system, then it may be most rational for some facilities to be shut down, or bypassed, causing some amounts of load shedding. In unusual circumstances, it is far more cost effective to interrupt service for a few hours or a few days in order to avoid prolonged outages caused by irreparable equipment damage, or destruction. The Commission has recognized that load

[48] *See* Rebuilding Electrical Infrastructure Along the Gulf Coast: A Case Study, Billy Ball, The Bridge: Linking Engineering and Society, Spring 2006.

shedding is an important operational tool. GMD Reliability Standards should allow for this practice as part of the operational procedures that may be adopted under both stage one or stage two standards, consistent with the Commission's rules and policies.

D. The Final Rule should allow for ISOs/RTOs to make tariff filings to provide for recovery of out-of-market costs incurred to comply with GMD Reliability Standards and GMD mitigation costs.[49]

The NOPR acknowledges that the proposed second stage Reliability Standards "will likely require an extended, multi-phase implementation period given the time needed to conduct the required assessments and the time and cost of installing any required automatic protection measures." However, it does not address the fact that such costs, as well as the cost of compliance with mandatory Reliability Standards in general, are often out-of-market costs for many generation facilities, such as those operated by merchant generators that do not serve retail customers and do not go before state public utility commissions. The Commission should address this issue in its Final Rule by allowing ISOs/RTOs to make tariff filings that permit generators to recover these types of costs.

The Trade Associations believe such an action would be consistent with the Commission's *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 at P 27 (April 19, 2004), wherein the Commission acknowledged that public utilities may need to expend significant amounts of money to implement measures necessary to maintain BPS reliability, including vegetation management, improved grid monitoring and management tools, and improved operator training. The

[49] Note that APPA and NRECA do not join in the section of these comments addressing recovery of out-of-market costs.

Commission specifically assured public utilities that it would approve applications to recovery prudently incurred costs necessary to ensure BPS reliability including compliance with NERC standards. *Id*. at P 28.

Some of these types of costs likely to be required as a result of the proposed Stage Two Reliability Standard are likely to be extraordinary and certainly to be imbued with the interest of national security. Investments to protect equipment for an event that may occur once in one hundred years or more will most likely not be compensated in the markets. While Trade Associations do not suggest that all reliability investments are out-of-market, certain extraordinary investments qualify at such (*e.g.*, replacing generator step-up transformers, investing in more spare transformers than normal for the purpose of sharing spare transformers during a national emergency). Thus, the Commission might consider a method to cover such costs. For example, in Order No. 761, the Commission noted that it had conditionally accepted a proposal by PJM to allow generators providing blackstart service to recover cost related to compliance with CIP Reliability Standards.[50] The existing Commission-approved cost-based mechanism for merchant generators to recover cost for the provision of reactive power is another potential model that could be pursued for the recovery of costs associated with GMD Reliability Standards. Accordingly, the Trade Associations urge the Commission to encourage the ISOs/RTOs to develop via their respective stakeholder processes recovery mechanisms that are appropriate to extraordinary investments that are in the national interest and would not be compensated through other market means.

[50] *See PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,020, at P 47 (2012).

CONCLUSION

WHEREFORE, for the foregoing reasons, the Trade Associations urge the Commission to consider these Comments and ensure that any future action ordered as a result of this proceeding is consistent as discussed above.

Respectfully submitted,

<u>/s/ James P. Fama</u>

Edison Electric Institute

James P. Fama
Vice President, Energy Delivery
Aryeh B. Fishman
Director, Regulatory Legal Affairs
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
(202) 508-5000

American Public Power Association

Allen Mosher
Vice President of Policy Analysis and Reliability Standards
1875 Connecticut Ave., NW
Washington, DC 20009
(202) 467-2944

Large Public Power Council

Jonathan D. Schneider
Stinson Morrison Hecker LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036-3816
(202) 785-9100

Counsel for Large Public Power Council

National Rural Electric Cooperative Association

Richard Meyer
Senior Regulatory Counsel
Patricia Metro
Manager, Transmission & Reliability Standards
4301 Wilson Boulevard
Arlington, VA 22203-1860
(703) 907-5811

Dated: December 21, 2012

APPENDIX A

I. EPRI SUNBURST Project

The EPRI SUNBURST project was initiated shortly after the March 13, 1989 solar event that precipitated the Quebec Hydro Blackout. Since that time, EPRI and industry has sought to better understand how geomagnetically-induced currents ("GIC") impact electrical equipment. The SUNBURST network is both an organized method for measuring GICs and their effects, and a source of data for continued research studying the cause, effects and mitigation of GIC impacts on electrical power systems. While the primary focus is operating the monitoring network for purposes of providing better situational awareness, the data collected in this project is beginning to be used to provide feedback into new prediction models that will serve as more directed advance warning systems, that is, the NASA Solar Shield project.

The SUNBURST network consists of a consortium of utilities who have allowed the near-real-time continuous monitoring of GIC on selected large power transformers largely placed to provide a broad perspective of GIC impacts across North America. By measuring these GICs along with current harmonics, the SUNBURST network helps to communicate the breadth, intensity, and localized transformer saturation impact as these storms occur. From the beginning this system was developed to "collect high-quality, readily accessible data related to geomagnetically-induced currents (GIC) associated with geomagnetic disturbances (GMD)" in order to better understand the effects and develop effect methods of modeling and ultimately more remediation.

II. NASA, NOAA, CCMC Industry Collaboration

Although efforts conducted by NASA[51], NOAA[52] and the Goddard Space Flight Center's Community Coordinated Modeling Center (CCMC) [53] go well beyond any effort possible by the industry on its own, it is only through these federal government agencies and the support and data they supply is the electric utility industry able to effectively respond to solar events. Furthermore, these collaborations are hoped will improve industry situational awareness over time. Presently, alerts generated from these systems, along with GIC monitoring, provide necessary notifications to the industry informing system operators in advance and throughout a solar storm.

III. EPRI GMD Project

Project Plan**:** The initial objective will be to determine the state of knowledge of GMD. This will include a review of the available literature and interviews of industry experts, to collect and validate industry data on the probability of extreme events and the extent to which storms can reasonably be anticipated.

Since the initiation of this project, EPRI has developed and released a "first release" of its open source modeling software which is hoped will help the industry determine how systems and equipment respond to various storm scenarios as well as

[51] NASA owns and operates a group of solar satellites whose data is used by the industry to inform and prepare for possible solar events which might negatively impact BPS operations. Among these systems include SOHO (http://sohowww.nascom.nasa.gov), Stereo (http://www.nasa.gov/mission_pages/stereo/main/index.html),and SDO (http://sdo.gsfc.nasa.gov).

[52] NOAA owns and operates the ACE Satellite which provides 30 – 60 minutes of advance warning of incoming space weather. Alerts from this system are often used by system operators to inform and prepare their operations in response to an incoming solar storm.

[53] The Goddard CCMC works with a variety of organizations and industries including the electric utility industry. Their role for the electric utility industry is to assist and improved their understanding, situational awareness and response. *See* http://ccmc.gsfc.nasa.gov/index.php. The Solar Shield Project is a collaborative project between the CCMC and the electric utility industry which intends to help better protect the electric power industry.

evaluate candidate mitigation technologies.

The project is also intended to evaluate the various new technologies and approaches being developed to help mitigate the impacts of GMDs on industry systems and assets. Ultimately, it is hoped that this center of expertise will be used to provide a knowledge base where the industry can test and assess mitigation technologies, perform system studies, answer industry questions and assess technical concerns.

Among the technologies EPRI will be testing are GIC blocking devices and assessing various operational strategies. Additionally, EPRI will assess mitigation solutions and strategies that purport to include technologies that may reduce the impact or duration of outages. EPRI also plans to consider how mitigation techniques might impact protected equipment, along with possible impacts to the BPS.

As a final deliverable, EPRI plans to develop a guidebook covering mitigation and recovery practices and emerging technologies for forecasting, early warning, operations, and restoration, as well as the various mitigation technologies.

APPENDIX B

I. The Trade Associations do not support the findings of the Oak Ridge National Laboratory Report -Meta-R-319 ("ORNL/Metatech Report") believing it to be flawed and lacking necessary peer review.

A. The Severe Geomagnetic Storm Scenario appears to use anecdotal evidence in ways that is unsupportable by the current body of scientific evidence.

Although the geophysical analysis assumed to be used in the ORNL/Metatech Report is valid and has been used in scientific papers and journals to analyze GIC impacts at a localized level, similar application on a broader scale as depicted in this report appears to be flawed and unsubstantiated by the current body of science. Specifically, spatially isolated observations used to infer severe geomagnetic storm levels of 4800nT/min appear to be based solely on such evidence, *i.e.*, isolated observations. For this reason, the Trade Associations believe the scenario to be flawed since the report extends pocketed localized measurements into very large, possibly continent wide, storms that extend into lower geomagnetic latitudes and does so without any known rigorous technical basis. The result is a storm scenario that lacks a scientifically defendable basis.

Furthermore, the Trade Associations understand that very intense upper atmospheric electrical currents (*i.e.*, electrojets) are manifested as a result of severe GMD events. The results are fluctuating currents that translate into spatial extensions of extreme geoelectric fields driving GIC of a very complex nature. The spatial extensions of complex extreme geoelectric fields are at this time poorly known. Specifically, given the current state of the science, the Trade Associations believe that to imply it can be known with any degree of certainty how an extreme storm would manifest itself over a broad region based on a limited number of peak historic measurements exaggerates what is presently known in the current body of science.

The Trade Associations also find other inaccuracies and inappropriate technical leaps made in the report. For example, the following statement is made in the report, "the observation of a ~2000 nT/min dB/dt was observed in March 13, 1989 in Denmark, ~2700 nT/min in mid-Sweden in July 1982, ~2200 nT/min again in March 24, 1991 in southern Finland, and on Aug 4, 1972 in North America. This sampling indicates that a disturbance of this size class can be expected at a frequency of approximately once or twice per solar cycle, *i.e.*, about a 1 in 10 year probability."[54] The Trade Associations believe that the assertion that a 2000 nT/min dB/dt can occur with a frequency of once every 10 years does not appear to be based on any rigorous statistical analysis, but on simple conjecture.

The Trade Associations are also concerned about apparent broad leaps within the ORNL/Metatech Report that appear to link separate and isolated events without the use of rigorous statistical analyses, and then use those links to speculate the outcome of a low frequency event. Specifically, the report justifies some observations and anecdotal information about the May 1921 storm[55] and then uses such information to justify inferences about the July 1982 Storm. For example, the report states that "based on the July 1982 paired observations and the linear behavior of geo-electric field response to the incident magnetic field environment, it is plausible to project that the disturbance

---

[54] *See* Meta-R-319, Geomagnetic Storms and Their Impacts on the U.S. Power Grid, Prepared for Oak Ridge National Laboratory at 3-13.

[55] *See id.* at 3-8.

intensity approached a level of ~5000 nT/min."[56] Given the proprietary nature of this report, it is impossible to say how this conclusion was made.

Finally, based on all of the noted conjecture, the ORNL/Metatech Report supports the 5000 nT/min as an observational fact, stating "as previously reviewed, the large ~5000 nT/min observed in May 1921 has occurred before and therefore is likely to occur again."[57] The Trade Associations believe this to be misleading since we are not aware of any rigorous statistical analysis that was performed to provide support for the selected extreme dB/dt and geoelectric field levels that were presented in the report and used as basis for the conclusions that were provided.

B. Voltage collapse due to increased reactive power demand does not appear to be based on any planning study and utilizes obsolete methods.

It is well-known that half-cycle saturation of transformer cores causes an increase in reactive power losses which can lead to a reduction in system voltage[58], and in some cases total system collapse if adequate reactive power resources are unavailable.[59] In order to determine if voltage collapse is likely (or even possible) during a specified GMD scenario, a power flow analysis, in concert with a GIC analysis, must be performed.[60] In such an analysis, GIC flow in transformer windings is used to estimate the resulting

---

[56] *See id.* 3-8.

[57] *See id.*. 3-13.

[58] *See* V. D. Albertson, J. M. Thorson, "Power System Disturbances During a K-8 Geomagnetic Storm: August 4, 1972," IEEE Transactions on Power Apparatus and Systems, July 1974, PAS-93, Issue 4, at 1025-1030.

[59] *See* NERC 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System; February 2012; at iii.

[60] *See* V. D. Albertson, J. G. Kappenman, N. Mohan, G. A. Skarbakka, "Load-Flow Studies in the Presence of Geomagnetically-Induced Currents," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 2, February 1981, at 594-607; *see also* Investigation of Geomagnetically Induced Currents in the Proposed Winnipeg-Duluth-Twin Cities 500 kV Transmission Line Final Report, EPRI Research Project EL-1949, July 1981. Available at www.epri.com.

reactive power loss. Using the estimated reactive power loss, transformers are then modeled as constant current reactive loads in the power flow. Therefore, accurate mapping of GIC to Mvar loss is essential to obtaining accurate results.

The analysis conducted as part of ORNL/Metatech Report failed to meet these basic requirements. First, power flow simulations were not performed as part of the analysis.[61] Secondly, the best available data[62] was not used to map GIC flows to reactive power losses. Third, no comprehensive assessment of harmonics load flows was conducted to support assessments of risk in this report. [63]

Figure 1-18 of ORNL/Metatech Report describes how the GIC were mapped to reactive power losses in three voltage classes of single-phase transformers. The linear mapping provided in Figure 1-18 of the ORNL/Metatech Report can be approximated using the following equation:

$$Q \approx \frac{\sqrt{3} \cdot k \cdot I_{gic} \cdot V}{10^6}$$

Equation 1

where Q is the three-phase reactive power loss (Mvars), k is equal to 2.0, I_{gic} is the

[61] *See* Meta-R-319; Appendix 1; Subsection A1.1; Overview of US Transmission Grid Design Criteria; at A1-4.

[62] *See* R. A. Walling, A. H. Khan, "Characteristics of Transformer Exciting-Current During Geomagnetic Disturbances," IEEE Transactions on Power Delivery, Vol. 6, No. 4, October, 1991, at pp. 1707-1714; *see also* R. A. Walling, A. H. Khan, "Solar-Magnetic Disturbance Impact on Power System Performance and Security Proceedings": EPRI Geomagnetically Induced Currents Conference, November 8-10, 1989, TR-100450. Available at www.epri.com; *and see also* D. H. Boteler, R. M. Shier, T. Watanabe, R. E. Horita, "Effects of Geomagnetically Induced Currents in the B.C. Hydro 500 kV System," IEEE Transactions on Power Delivery, Vol. 4, No. 1, January 1989, at 818-823.

[63] *See* Meta-R-319; Appendix 1; Subsection A1.1; Overview of US Transmission Grid Design Criteria at A1-4.

per-phase GIC (Amps/phase) and *V* is the nominal line-to-line voltage of the system (Volts). Choosing a value of 2.0 for *k* suggests that the reactive power loss was computed using the *rms* value of the exciting-current instead of its 60 Hz component only. This is further evidenced by the following statement in Appendix 4 of ORNL Report: "Once the harmonics currents are available, it is straightforward to calculate the reactive power."[64] This method of computing reactive power losses due to half-cycle saturation has its roots in earlier works [65] but has since been proven obsolete. [66] Inclusion of harmonic exciting-current components in the reactive power loss definition, and then using such results as reactive load models to represent half-cycle saturated transformers in a power flow analysis that is limited to fundamental frequency representation yields erroneous results by grossly overestimating the reactive losses.[67] The reactive losses computed using Equation 1 are overestimated by approximately 60% or more when compared to those estimated using the 60 Hz exciting-current based methods.[68]

[64] *See* Meta-R-319; Appendix 4 at A4-1.

[65] *See* V. D. Albertson, J. G. Kappenman, N. Mohan, G. A. Skarbakka, "Load-Flow Studies in the Presence of Geomagnetically-Induced Currents," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 2, February 1981, at pp. 594-607. *Also see,* Investigation of Geomagnetically Induced Currents in the Proposed Winnipeg-Duluth-Twin Cities 500 kV Transmission Line Final Report, EPRI Research Project EL-1949, July 1981. Available at www.epri.com.

[66] *See* R. A. Walling, A. H. Khan, "Characteristics of Transformer Exciting-Current During Geomagnetic Disturbances", IEEE Transactions on Power Delivery, Vol. 6, No. 4, October, 1991, at 1707-1714. *Also see,* R. A. Walling, A. H. Khan, "Solar-Magnetic Disturbance Impact on Power System Performance and Security Proceedings": EPRI Geomagnetically Induced Currents Conference, November 8-10, 1989, TR-100450. Available at www.epri.com. *And also see,* D. H. Boteler, R. M. Shier, T. Watanabe, R. E. Horita, "Effects of Geomagnetically Induced Currents in the B.C. Hydro 500 kV System," IEEE Transactions on Power Delivery, Vol. 4, No. 1, January 1989, at 818-823.

[67] *See* R. A. Walling, A. H. Khan, "Characteristics of Transformer Exciting-Current During Geomagnetic Disturbances," IEEE Transactions on Power Delivery, Vol. 6, No. 4, October, 1991, at 1707-1714.

[68] R. A. Walling, A. H. Khan, "Solar-Magnetic Disturbance Impact on Power System Performance and Security, Proceedings": EPRI Geomagnetically Induced Currents Conference, November 8-10, 1989, TR-100450. Available at www.epri.com. *And see also* D. H. Boteler, R. M. Shier, T. Watanabe, R. E. Horita, "Effects of Geomagnetically Induced Currents in the B.C. Hydro 500 kV System," IEEE Transactions on Power Delivery, Vol. 4, No. 1, January 1989, at 818-823.

Additionally, the reactive losses provided in the ORNL/Metatech Report assume nominal system voltage. During a GMD, the system voltage will become depressed resulting in further reduction in reactive loss.

Finally, the method used to compute reactive power losses assumes a linear relationship between GIC and Q for all transformer types. Work by Walling and Khan illustrates that a non-linear relationship exists for certain types of three-phase transformers, in particular five-legged core construction.[69] The non-linear relationship has the effect of significantly reducing the reactive power loss caused by half-cycle saturation of the core. The resulting reactive power loss can be on the order of 50% of that estimated by a standard linear mapping for three-phase transformers. [70]

C. Transformer Damage due to Increased Hot-Spot Heating appears to be based on arbitrary limits that have no known basis.

The transformer vulnerability assessment that was performed in ORNL/Metatech Report appears to have used an arbitrarily chosen limit of 90 Amps per phase to define GIC withstand of transformers. The Trade Associations are unaware of any theoretical foundation for the use of the limit as provided.

It is well-known that time-independent criteria are not suitable for the assessment of GIC impacts to power transformers.[71] Time constants of transformer windings and

---

[69] *See Figure 7* of R. A. Walling, A. H. Khan, "Solar-Magnetic Disturbance Impact on Power System Performance and Security Proceedings": EPRI Geomagnetically Induced Currents Conference, November 8-10, 1989, TR-100450.

[70] *See id.*

[71] *See, e.g.*, L. Marti, A. Rezaei-Zare, A. Narang, "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," IEEE Transactions on Power Delivery, 2012, 10.1109/TPWRD.2012.2224674; *see also* T. Ngnegueu, F. Marketos, F. Devaux, T. Xu, R. Bardsley, S. Barker, "Behavior of Transformers under dc/GIC Excitation: Phenomenon, Impact on Design/Design Evaluation Process

metallic parts are usually on the order of 3-5 minutes[72] meaning that it takes approximately 15-25 minutes for the winding or metallic hotspot temperature to reach their steady-state values. Large GIC associated with a severe GMD are of short duration with pulse widths typically less than the thermal time constant of the transformer windings. Thus, transformer hotspot temperatures would not reach steady state levels during a GMD. To illustrate, Fig. 1 depicts the resulting GIC and hotspot temperature associated with a 20V/km geoelectric field.

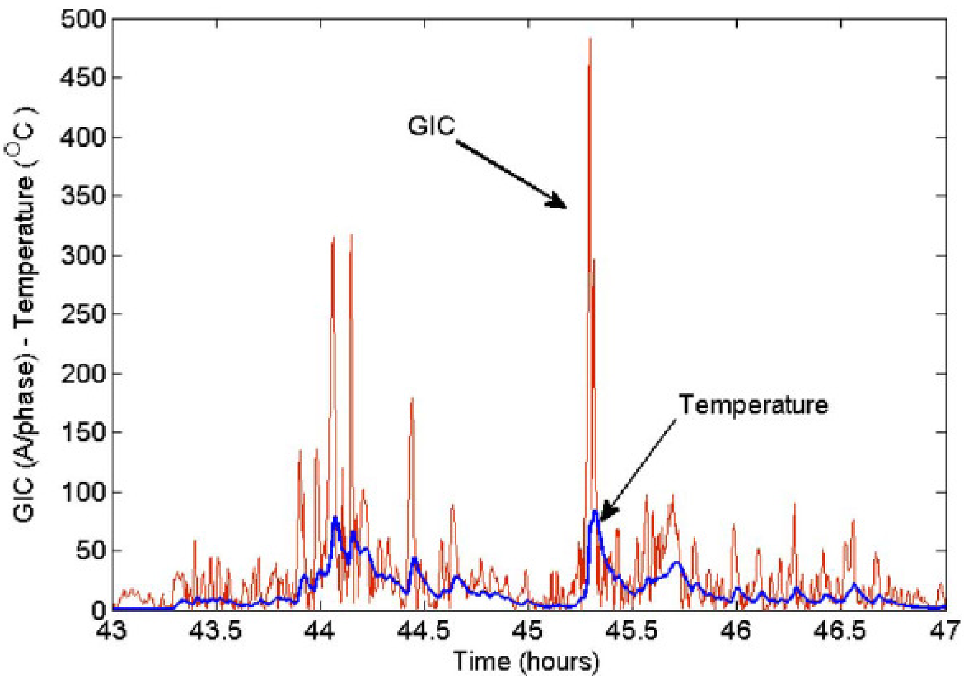

Figure 1. Transformer tie-plate hotspot temperature rise versus time.[73]

---

and Modeling Aspects in Support of Design", CIGRE 2012; *and see also* P. Picher, L. Bolduc, A. Dutil, V. Q. Pham, "Study of the Acceptable dc Current Limit in Core-Form Power Transformers," IEEE Transactions on Power Delivery, Vol. 12, No. 1, January 1997, at 257-265; *and see also* R. Girgis, K. Vedante, K. Gramm, "Effects of Geomagnetically Induced Currents on Power Transformers and Power Systems,"A2-304, CIGRE 2012.

[72] *See* P. Hurlet, F. Berthereau, "Impact of Geomagnetic Induced currents on power transformer design," IEEE Conference MATPOST'07 - LYON (France).

[73] *See figure 10 in* L. Marti, A. Rezaei-Zare, A. Narang, "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," IEEE Transactions on Power Delivery, 2012,

GIC of approximately 475 Amps/phase was not sufficient to raise the hotspot temperature beyond the critical threshold of 130ºC (based on short-time emergency limits provided in the IEEE Guide[74] for Loading Mineral-Oil-Immersed Transformers. Similar results can be found in an IEEE Transaction paper titled "Calculation Techniques and Results of Effects of GIC Currents as Applied to Two Large Power Transformers;"[75] This underscores the importance of using time-domain based thermal models as opposed to arbitrary limits when assessing the performance of transformers subjected to GIC.

II. The Trade Associations find errors of omission in the ORNL/Metatech Report.

The Trade Associations believes the three key events in the ORNL/Metatech report which do not fully disclose information which is necessary to fully assess the risk posed by GICs resulting from a severe GMD event. The three events that the Trade Associations have focused on include the Hydro Quebec Blackout, the PSEG/Salem transformer failure and the Eskom transformer failures. Each having played a role in shaping current concerns over the risks associated with GMD events yet each contain nuances if not fully understood can lead to incorrect conclusions.

A. March 13, 1989 Hydro-Quebec Blackout lessons learned vary greatly between the ORNL/Metatech Report and PNNL Report.

The Trade Associations believe that the ORNL/Metatech Report minimized important improvements made by Hydro Quebec after the 1989 blackout. Although the report does acknowledge these improvements in Section 2 of the report, it goes on to

10.1109/TPWRD.2012.2224674.

[74] *See* IEEE Std. C57.91-1995 IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

[75] *See* R. Girgis, K. Chung-Duck, "Calculation Techniques and Results of Effects of GIC Currents as Applied to Two Large Power Transformers", IEEE Transactions on Power Delivery, Vol. 7, No. 2, April 1992.

suggest events of an even greater magnitude could occur risking the U.S. grid.[76] For example, in the report it states that "[d]uring the process of collapse, permanent damage was inflicted on the Quebec power grid."[77] The ORNL/Metatech report also taints equipment such as a static var compensator ("SVC") as posing a risk to "widespread grid collapse"[78], while the Trade Associations do not dispute that the loss of SVCs were a large contributor to the Hydro Quebec Blackout, the cause (23 years later) is more thoroughly understood and recognized to be completely manageable. Furthermore, the Trade Associations believe that SVCs if properly configured should not contribute to collapse but will greatly aide in maintaining system stability during GMD events. To this point, the Trade Associations offer a significantly different set of findings as provided in the PNNL Report.

Among the lessons learned by Hydro Quebec, as detailed in the PNNL Report include:

- SVCs were found to be capable of handling the GIC effects but the settings did not allow them to provide protection. Settings have since been adjusted.
- Additional SVCs have been added to provide additional support.
- Large power transformers were found to be much more tolerant of dc in the windings than had been expected.
- A scheme for blocking dc in transformer neutrals was developed, and pilot was

[76] *See* Meta-R-319 at 2-5 to 2-6, which acknowledges both hardware and operational improvements have been made. However, the Trade Associations believe that had these improvements been more thoroughly described in the report it may have arrived at different conclusions. Furthermore, rather than discussing these improvements the report suggests the possibility of even larger threats than before.

[77] *See* Meta-R-319; at 2-12, paragraph 1, wherein equipment damage is highlighted rather than methods of mitigation which the Trade Associations believe were the real lessons for the industry.

[78] *See id.* at 2-12, paragraph 1 where the report highlights the risks of SVC as new technology which is certainly no longer the case and other reports highlight their value in stabilizing GMD events if properly utilized and protected.

installed. However, the need for these devices was later determined to be unnecessary because other more proven methods were used.

- Additional series line capacitors were added to further mitigate the risk of GICs in the region.[79]

B. Hydro Quebec Blackout Damaged Equipment

The 1989 Hydro Quebec Blackout, is often used in the ORNL/Metatech Report to assert that wide spread collapse and permanent equipment damage is a likely outcome of a severe GMD event.[80] Although the Trade Associations agree that both are potential risks of a severe GMD event, the Trade Associations find the conclusions of the GMD Task Force, which states that "the most likely worst-case system impacts from a severe GMD event and corresponding GIC flow is voltage instability caused by a significant loss of reactive power support,"[81] to be more credible and based on the scientific facts. The Trade Associations also note that while Section 2 of the ORNL/Metatech Report appears to properly characterize the Hydro Quebec incident, the Trade Associations are troubled by the mixing of this event within Section 4 of the report which is largely intended to addresses equipment damage resulting from GIC and transformer heating. In the following excerpts from Section 4.0 of the ORNL/Metatech Report, the Trade Associations note the following scenario presented to the reader when assessing the impacts of a severe GMD event:

---

[79] *See* Pacific Northwest National Laboratory, Report No. PNNL-21033, Section 5.3; Hydro Quebec Follow Up at 17.

[80] *See* Meta-R-319 Geomagnetic Storms and Their Impacts on the U.S. Power Grid at 2-12; paragraph 1. In this section there is a description of the damage that occurred during the Hydro Quebec Blackout which appears to conform to the sequence of events as documented by NERC. *However, in contrast* Section 4 of this report (at 4-2) contains a description of a severe GMD event that describes large numbers of transformers that are permanently damaged. Following this description, the Hydro Quebec Blackout is discussed which we find inappropriate since no transformers were damaged directly by GICs during this event.

[81] *See* NERC 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System; February 2012; at Subsection I.9 - Conclusions, at vi.

- This extended recovery would be due to permanent damage to key power grid components used by the unique nature of the electromagnetic upset.[82]

- Both HEMP and space weather disturbances, however, can have a sudden onset and cover large geographic regions. They therefore cause near simultaneous, correlated, multipoint failures in power system infrastructures, allowing little or no time for meaningful human interventions that are intended within the framework of the N–1 criterion. This is the situation that triggered the collapse of the Hydro Quebec power grid on 13 March 1989, when their system went from normal conditions to a situation where they sustained seven contingencies (*i.e.*, N–7) in an elapsed time of 57 seconds. The province-wide blackout rapidly followed, with a total elapsed time of 92 seconds from normal conditions to a complete collapse of the grid."[83]

- The more difficult aspect of this threat is the determination of permanent damage to power grid assets and how that will impede the restoration process. As previously mentioned, transformer damage is the most likely outcome (although other key assets on the grid are also at risk).[84]

- In particular, transformers experience excessive levels of internal heating brought on by stray flux when GICs cause the transformer's magnetic core to saturate and to spill flux outside the normal core steel magnetic circuit.

Although the Trade Associations do not dispute that two transformers were damaged during the Hydro Quebec network collapse, none of this equipment was damaged as a direct result of GICs.[85] The Trade Associations believe this is an important fact that is lost in the case being made in Section 4[86] that is intended to suggest transformers as those elements most at risk and most likely to cause extended system

[82] *See* Meta-R-319 at 4-1; paragraph 1. The Trade Associations note that no equipment was damaged as a direct result of GIC during the Hydro Quebec Blackout.

[83] *See id.* at 4-1 to 4-2; paragraph 2. The Trade Associations are concerned that the Hydro Quebec incident is inappropriately used to provide a scenario for damage resulting directly from GICs when none occurred.

[84] *See* Meta-R-319 at 4-2; paragraph 1. The Trade Associations note that no transformers were damaged through GIC heating during the Hydro Quebec Blackout.

[85] In the NERC Report, Page 42; Column 2, which detailed the event of the "March 13, 1989 Geomagnetic Disturbance/Hydro Quebec Blackout," identifies that the transformers were damaged due to overvoltage. Damage to Equipment http://www.nerc.com/files/1989-Quebec-Disturbance.pdf; *see also* PNNL-21033 at 16 (stating that "no equipment damage resulted directly from the GIC").

[86] In Section 4 of Meta-R-319, at 4-1 to 4-23, wherein the case is made that GICs pose a large risk to power transformers due to heating effects of GICs on large power transformers. Including the Hydro Quebec Blackout in this section only serves to confuse the issue since there were no transformers damaged due to the direct effect of GICs.

outages extending into years due largely to transformer heating. This is also an important fact given the only transformer known to have failed over the last 23 years in North America as a direct result of GICs was the PSEG/Salem transformer which was particularly vulnerable to such effects.[87] Furthermore, in the PNNL Report it notes in Section 5.3 (Hydro Quebec Follow up) "large power transformers were found to be much more tolerant of dc in the windings than had been expected."[88] This is a fact that was never mentioned in the ORNL/Metatech Report.

C. PSEG/Salem Nuclear Power Plant Transformer Damage

The Trade Associations believe that the PSEG/Salem Nuclear Power Plant transformer damage that occurred during the March 13-14, 1989 Geomagnetic Storm due to GICs is a poor example of transformer risks across North America.

The Trade Associations also understand that the PSEG/Salem generator step-up ("GSU") transformer that was damaged during the March 1989 solar storm represents a poor example for use in assessing industry GMD/GIC risks. Although this transformer was damaged due high levels of GIC currents, it was an obsolete transformer design which is now known to have vulnerabilities to GICs.[89] Additionally, the Trade Associations understand this design has not been used by transformer manufacturers since the mid-1970s.[90] The Commission should recognize that given the vintage of this transformer design, it likely does not represent a large risk to BPS reliability.

[87] *See* description of PSEG/Salem Nuclear Power Plant Transformer Damage.

[88] PNNL-21033, at 17, bullet 3.

[89] Effects of GICs on Power Transformers and Power Systems, R Girgis, ABB Power Transformers, St. Louis, MO, at 5.

[90] *See id.*

Furthermore. GIC risks are not based solely on transformer design but require significant GICs modeling developed through transmission planning studies and detailed transformer GIC withstand capability studies of which none were done in support of the ORNL/Metatech Report.

The Trade Associations observe that the response of the PSEG/Salem GSU to GIC appears to be extrapolated to represent the thermal performance of the transformer fleet resulting in what appears to be an unrealistic conclusion. Salem GSU had known design flaws that made it uniquely susceptible to hot-spot heating caused by half-cycle saturation. The excessive hotspot temperatures that the Salem GSU experienced are attributed to a low-voltage lead consisting of about a hundred strands and connected by massive welding joints to two parallel sections of the low-voltage winding allowing a considerable circulating current to be established once half-cycle saturation occurred.[91]

D. Eskom (South Africa) Transformer failures may have failed due to contaminated transformer oil with GICs only acting as a secondary contributor.

The Trade Associations are concerned by the depiction of transformer failures at Eskom as detailed in the ORNL/Metatech Report. In this report it states that "Eskom grid (South Africa) sustained the loss of 14 large 400kV transformers over the October 29-31, 2003 geomagnetic storm. Therefore, these lower latitude regions in combination with high latitude regions of North America and Europe could all experience substantial disruptive events from an extreme storm, effects that could include permanent damage to key power system apparatus."[92] Although this characterization is in part accurate, it does

[91] R. Girgis, K. Chung-Duck, "Calculation Techniques and Results of Effects of GIC Currents as Applied to Two Large Power Transformers," IEEE Transactions on Power Delivery, Vol. 7, No. 2, April 1992.

[92] *See* Meta-R-319, at 3-27

not tell the entire story or detail other mechanisms that likely contributed to these failures. Specifically, what is known is that the levels of GICs, appears to be insufficient to have caused these transformer failures. [93] The Trade Associations also understand, but cannot confirm, that copper sulfides were discovered in the transformers that failed.[94] In furtherance of this understanding the Trade Associations note the following:

> "Other cases were reported in Reference [5] [95] of significant winding overheating in a number of large core form power transformers in S. Africa during the period between 2003 and 2004. These incidents were found to coincide with failures caused by the phenomenon of the conducting Copper Sulphide forming and causing failures of transformers world – wide; related to the Sulphur content in the mineral oil used in these transformers." [96]

The Trade Associations also note that the copper sulfide (sulphide) phenomenon is more widely understood and that transformer oil contaminated with corrosive sulfur can over time through heating create copper sulfide that is highly corrosive and is known to damage transformer paper insulation often leading to premature transformer failures. [97] Furthermore, these effects have been widely studied worldwide and it in North America it

---

[93] *See* Effects of GIC on Power Transformers and Power Systems, Section IV Reported Transformer Damage/Overheating Contributed to GIC, R. Girgis, ABB Power Transformers, St. Louis, MO, at 6, paragraph 1.

[94] *See* Transformer Failures in regions incorrectly considered to have low GIC-risk, CT Gaunt, G Coetzee, IEEE Transaction, 978-1-4244-2190-9/07 © 2007. The Trade Associations have been given some circumstantial evidence regarding that transformer failures in South Africa that indicate that Copper Sulfides may have contributed to the transformer failures at Eskom. We also received a presentation at a Cigre event which cites some transformer failures in South Africa resulting from copper sulphides. *See* Cigre SC-A2 Colloquium "Transformer Reliability and Transients," at 20-24 June, 2005, Moscow, Russia.

[95] *See* C. T Gaunt, G. Coetzee, "Transformer failures in regions incorrectly considered to have low GIC-risk," Mat Post 07, 3rd European Conference on MV & HV Substation Equipment, Nov 15-17, 2007, Lyon, France, Proceedings of Power Tech, July 15, 2007, Lausanne, Switzerland, at p. 4 VI. Contained in this paper includes a description of other possible causes of damage.

[96] *See* Effects of GIC on Power Transformers and Power Systems, Section IV Reported Transformer Damage/Overheating Contributed to GIC, R. Girgis, ABB Power Transformers, St. Louis, MO; at 6, Paragraph 1.

[97] *See* The Role of Corrosive Sulfur in Transformers and Transformer Oil, Lance R. Lewand, Doble Engineering Company, USA – 2002; s*ee also* Investigating Copper Sulfide Sulfide Contamination in a Failed Large GSU Transformer, Lance Lewand, Doble Engineering Company – 2005; *and* Update on the Corrosive Sulfur Issue in Oil-Filled Electrical Equipment, Lance R. Lewand and Paul J. Griffin; Doble Engineering Company - 2006.

appears that the risks are well managed through routine maintenance practices including routine oil sampling and testing, chemical mitigation processes and testing. Therefore, the Trade Associations believe any assertion that these transformers failed in mass solely due to GICs is conjecture and is no more a proven fact than copper sulfides are known to be the root cause of these failures.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

White Paper Outline

Cost/Benefit, Load Loss, Cascading Task Team

Introduction

At its meeting in February 2011, the Member Representatives Committee (MRC) was asked to advise the Board on any policy issues related to the definitions of Bulk Electric System (BES) and Adequate Level of Reliability (ALR). A subgroup of the MRC, leadership of NERC's Standing Committees, select experts, and NERC staff, was formed to address these specific policy issues — MRC BES/ALR Policy Issues Task Force.

Reliability priorities cannot be addressed without a common understanding of the meaning and scope of reliability, as well as what criteria will be used to determine ALR.[1] Therefore, the MRC task force assigned the following questions regarding the ALR definition to an ad hoc team, which prepared this draft white paper outlining its views on three interrelated questions on the definition of ALR:

1. How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues] ***Cost/Benefit***
2. Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as *"X"* MWs in a rural area? ***Load Loss***
3. How should "cascading" be defined? ***Cascading Defined***

A specific "*Issue Summary Format*" was suggested that includes the Issue statement, Recommendations, Background, and Options and Analysis, including advantages and disadvantages of each option.

Issue 1: Cost/Benefit

Issue:

How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues]

[1] http://www.nerc.com/files/Adequate_Level_of_Reliability_Defintion_05052008.pdf

Recommendation: [Option 2]

Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.

Background:

The objective of the Task Team is to advise on the policy ramifications of whether the explicit incorporation of cost/benefit analysis is warranted within the ALR measurable criteria.

In the past, an essential element in the way NERC's current Reliability Standards were developed included processes to secure input from all stakeholders as well as balloting for approval of reliability standards. These aspects of NERC's stakeholder process inherently attempt to balance cost/benefit of a reliability objective with cost-effective requirements within a standard. An important consideration of reliability is cost balanced with the associated reliability benefits. Reliability investments, captured in NERC's Reliability Standards, compliance program, alerts, and other initiatives, are driven by overall objectives of balance among reliability and cost effectiveness to customers and ratepayers. It is important to achieve reliability risk mitigation in a manner that balances affordability of electricity in a global, competitive market, with the need to ensure the reliable performance and security of the North American electricity infrastructure. Priorities must be driven by a clear understanding of risks and consequences, along with the costs and benefits associated with addressing them.

As a first step, ALR criteria provide suitable and measureable reliability benefits, along with an assessment of unacceptable consequences. Risk information provides useful input to determine reliability benefits, though reliability objectives can, at times, include "defense-in-depth," considerations, where the resulting impacts on reliability (consequences) are deemed not acceptable, even though the risks may be low.

Once the reliability objectives have been refined to provide the desired reliability benefits, measureable cost-effective approaches or alternatives should be investigated. The reasonable balancing point between reliability benefits and cost-effective approaches is difficult to articulate in the abstract. For example, certain ALR criteria may provide a good measure of reliability benefits, but may not reach the balance point between cost and reliability. At first, it may be impossible to provide an acceptable balance, until the ALR is measured against specific case studies, which can be indicative of reasonableness. At the same time, the current recognized level of reliability in the North American grid can be considered to generally reflect an implicit recognition of the inherent economic/cost effective balance. Such balance points provide a long-term calibration of the validity of the current set of ALR factors, which should shift only gradually over time as the implications are potentially significant capital investments are needed to alter the balance. Yet, as additional information is obtained over time, adjustments or refinements can be made to ensure clarity in the balance of reliability objectives and cost-effective actions.

While a complete and detailed cost-effective assessment would theoretically include not only system-specific technical solutions, but represent jurisdictional considerations, and local impacts, the policy consequences of making such explicit calculations are manifestly difficult, widely susceptible to varying assumptions, inputs, and resulting conclusions. These economic effective aspects of reliability concerns are best represented by Federal jurisdictions for interstate and international responsibilities, and State/Provincial/Local regulators and end-user stakeholder groups for local considerations to ensure reliability objectives are met in a jurisdictionally cost-effective appropriate fashion.

However, on a macro level, NERC can work with its stakeholders to provide North American-wide greater transparency of the cost effectiveness of potential reliability initiatives with high-level estimates that can then be balanced against reliability objectives. In this way, making some explicit recognition of the cost effectiveness balanced against the reliability benefit objectives, can lead to adjustments to ensure that reliability objectives and cost-effective approaches remain balanced.

Options and Analysis:

PROS and CONS for each option that state the arguments for and against that option.

Option#	Option	Advantages	Disadvantages
1	Do not explicitly calculate or measure cost/benefit for Reliability Standards or ALR Criteria. Measurable criteria for ALR, once vetted by industry, would consider cost/benefit. Current approach for Standard generation and RoP 1600 for Data or Information, considers cost/benefit as part of industry review and comments. Also, existing Reliability Standards such as TPL (N-1), etc. are part of industry's ability to account for jurisdictional cost/benefits.	Each jurisdiction assesses Reliability Standards and RoP based on cost/benefit specifics based on their own situation. Measurable ALR criteria, including data requirements, would be vetted by industry and jurisdictional costs/benefits would be included in this assessment.	No rigorous calculations completed. Regional/ subregional, individual assessment comparisons not possible. Industry-wide costs not accounted for, relative to potential benefits.

Option#	Option	Advantages	Disadvantages
2 (Selected)	*Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.*	*Ensures that reliability objectives are balanced against more explicit recognition of cost-effective aspects.*	*High level analysis will not necessarily consistently predict localized cost/benefits. Specific cost-effective solutions will vary depending on system specifics and jurisdictional considerations.*
3	Measure cost/benefit for ALR Criteria.	Rigorous comparison available. Regional/ subregional, individual assessment comparisons possible. Industry-wide costs not accounted for, relative to potential benefits.	No consistent way to comparatively complete this analysis.

Issue 2: Load Loss

Issue:

Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as *"X"* MWs in a rural area?

Alternative statement of question: *To what extent is load loss, and its root causes, considered evidence of an inadequate level of reliability?*

Recommendation: [Option 1]

Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.

Background:

The focus is directing efforts on determining to what extent load loss classifications should be made and how should they be incorporated into the definition of ALR. The goal is to determine what circumstances that load loss represents actions in support of ALR (i.e., Energy Emergency Alert – EEA3) and those instances in which it doesn't. As a result, only a portion of incidents occurring on the bulk system that include load loss, reflect an inadequate level of reliability, while the balance reflect controlled system actions as designed and operated.

To provide a basis for this aspect of the definition of ALR, there must be a differentiation between uncontrolled load loss caused by unexpected failures, and intentional, controlled load loss either by design or manually initiated, perhaps as part of Emergency Operating Procedures or planning design criteria, executed to maintain bulk power system reliability. Load reduction is a vital component in design and an essential operational tool for preserving the overall stability and integrity of the grid, avoiding more widespread and severe consequences, such as cascading of the bulk electric system. FERC has in several instances raised the notion of continuity of service to customers as a factor that should be considered. However, the load loss attributes are diverse, in part dependent on the nature and design of the interconnection and, for purposes of defining load loss as an attribute of an adequate level of reliability, requires greater discrimination. Those aspects that industry depends upon to preserve the integrity of the bulk electric system is separate conceptually from end-use customer service goals – recognizing that from an end-use customer perspective, an outage is directly consequential on them.

Load loss or reduction needed to preserve reliability is part of the design basis or operational procedures to ensure the bulk power system remains stable, that all power flows and voltages remain within applicable ratings, and the system is able to withstand a critical contingency, without resulting in bulk power system instability, uncontrolled separation or uncontrolled cascading; e.g., under-frequency/undervoltage load shedding, manual load shedding, etc., depending on jurisdictional requirements and operating conditions.

In normal situations, if a bulk electric system element is lost, based on design, no load is lost. In other instances, 'consequential' load loss is directly designed/anticipated through the bulk system protection and network topology that, for example, interrupts a transmission circuit due a lightning strike or equipment failure with tapped transformers with attached load supply thereby localizing and controlling the extent of the disruption. Load reduction that is part of the design basis and operating procedures. Correct protection scheme operation provides the control needed to maintain reliability, and thus load loss by itself does not reflect an inadequate level of reliability.

The goal is to ensure that there is no uncontrolled load loss resulting from credible contingencies and events, as defined in NERC's Reliability Standards. However, uncontrolled load loss can result from extreme events (severe weather, earthquakes, etc.). That said, due to the resiliency of the bulk power system, industry addresses these extreme events with an orderly restoration and recovery of the bulk electric system to service, along with system reconstruction as needed. In addition, for high-impact, low frequency event risks, NERC's Severe Impact Resiliency Task Force will provide guidance and options to enhance the resilience of the bulk power system to withstand and recover from three severe-impact events (Coordinated physical and cyber attacks or geomagnetic disturbances) as described in the Coordinated Action Plan.[2]

Therefore, the amount and duration of load loss is not, by itself, an appropriate interpretation of event severity or an indicator of an inadequate level of reliability – rather those types of load losses resulting from uncontrolled or cascading actions on the bulk system or resulting from mis-operations would be indicative of an inadequate level of reliability. Even in severe weather/storm conditions where the loss of load is an anticipated consequence, the most relevant aspect for ALR purposes is the resilience/recovery aspect, rather than the direct measure of load lost. To this extent, some additional reflection of the resilience and recovery aspects should be incorporated in the ALR elements. NERC has recognized the need to measure relative severity and risk to reliability, through the development of its Risk/Severity metrics, where weightings of various events include the amount of lost generation, transmission, and if it occurs, both controlled and uncontrolled load loss.

Options and Analysis:

Option #	Option	Advantages	Disadvantages
1 (Selected)	*Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.*	*Develop categories of supply, transmission and controlled/ uncontrolled load loss based on a set of agreed upon causes. Also gather the affect of load loss, including duration and customer type (residential, commercial and industrial).*	*Must be clear and concise definitions and categorization. Otherwise, inaccurate interpretations could result.*
2	Do not include load loss in the ALR criteria.	Easy to implement. Load loss is only an indication of the relative severity, but sever events can occur without load loss.	Identification of causes and impacts could be lost.

[2] http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf

Issue 3: Definition of Cascading

Issue:

How should “cascading” be defined?

Recommendation: [Option 1]

No change to Cascading definition.

Background:

The Task Team’s goal is to define cascading, in light of the cost/benefit and load loss recommendations, and to make this a measurable part of ALR criteria.

The current definition in NERC’s Glossary[3] for Cascading is:

> *The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.*

“Cascading” is included in the statutory language of FPA Section 215 (a)(4) in the definition of “reliable operation:”

> FPA Sec 215 (a)(4): *“The term ‘reliable operation’ means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such a system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements”*

Assessment of Cascading is a system planning and operational planning activity; operators can intervene with the processes already developed, once it begins. Planners test the bulk power system for B, C and D category events as defined in the TPL[4] Reliability Standards. If the bulk power system cannot survive these tests, Cascading is assumed to result. In NERC’s TPL Reliability Standards, a number of extreme contingencies resulting in the unplanned loss of two or more (multiple) elements are studied (Category D events) to test the system’s robustness and evaluate the reliability risks and consequences of such extreme contingencies. These extreme contingencies may result in substantial loss of load and/or generation in a widespread area or areas. Portions or all of the interconnected systems may or may not achieve a new, stable

[3] http://www.nerc.com/files/Glossary_of_Terms_2011Mar15.pdf

[4] http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

operating point. The extreme event evaluation may require joint studies with neighboring systems. Planning Coordinators and Transmission Planners study these extreme events annually.

As described above, Cascading is far more than results from a single relay misoperation. For several decades, reliability has meant preventing Cascading, preserving the integrity of the grid, and providing an adequate bulk power supply. This could mean local load shedding to ensure that the effects from system failures are localized and managed so as to not spread.

The Federal Energy Regulatory Commission (FERC) has, in several instances, raised the notion of continuity of service to customers as an additional factor for consideration. However, there must be a differentiation between intentional load shedding used as an essential operational tool, and load loss caused by transitioning into abnormal operating states. Jurisdictional issues are also an important consideration, as increased costs may result from adding facilities which are focused on load loss reduction brought on by system failures.

If normally expected preparations by planners, operational planners and operators are undertaken, and events unfold as expected, then the event should not be classified as a cascade. However, if the bulk power system transitions in an unplanned, unexpected manner into an abnormal operating state, which results in uncontrolled system element and/or load loss, then the event should be classified as cascading.

Options and Analysis:

Option #	Option	Advantages	Disadvantages
1 (Selected)	*No change to the definition of Cascading.*	*Easy to implement and measurable. The following information can be probed to measure cascading events:* *1. Transmission Availability Data* *2. Generator Availability Data* *3. Events Analysis database and OE-417* *As suggested in the "Load Loss" response, further data collection on the controlled/ uncontrolled load loss can add measurability*	*None*

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Conclusions and Actions

The task team reviewed each of the three issues, and, for each, developed a recommendation for each to guide the standing committee's Adequate Level of Reliability Task Force (ALRTF):

1. How should cost/benefit be factored into ALR? How and by whom should those decisions be made? [Jurisdictional issues]*:*

   Recommendation: *Assess the reliability objectives of ALR criteria and provide an explicit recognition of high-level macro cost-effectiveness of requirements within a reliability standard to meet the reliability objectives.*

2. Is the impact of all load loss equal? For example, is the impact of *"X"* MWs of load loss in a major metropolitan area the same as "*X*" MWs in a rural area?

   Recommendation: *Revise ALR defining criteria to differentiate among the different characteristics of loss of supply, transmission and load loss as a function of planning design, operator preparations and ability to control outcomes from events; and refine the incorporation of resilience and recovery in the ALR elements.*

3. How should "cascading" be defined?

   Recommendation: *No change to the definition of Cascading.*

Electromagnetic Pulses (EMP)

Background

- The potential impact of electromagnetic pulses (EMP) on the electric system is a topic of ongoing discussion within and beyond the U.S. electric utility industry.
- EMP refers to a very intense pulse of electromagnetic energy impacting a specific area. Such a pulse could damage all electronics within the impacted area, potentially including elements of the electric transmission system.
- There are two potential sources of EMP:
  - Nuclear EMP – Refers to EMP caused by the detonation of a nuclear weapon at a high altitude to maximize its effect. A nuclear EMP is capable of creating wide-scale damage (i.e., potentially spanning hundreds of miles) and could damage all manner of consumer electronics. Damage may also extend to electric utility substations, power grid control devices, communications systems, power generation facility controls, etc.
  - Non-nuclear EMP – Refers to EMP created by smaller (non-nuclear) land-based weapons known as intentional electromagnetic interference (IEMI) weapons. Militaries have developed high- and low-frequency EMP weapons in order to attack targeted strike zones. An IEMI is intended to cause localized damage only (i.e. an individual building or substation).
- EMP should not be confused with the naturally occurring electromagnetic pulses created by geomagnetic disturbance (GMD) events. While GMD events are sometimes referred to as "naturally occurring EMP," the two phenomena are very different from a technical standpoint. Although EMP is often discussed along with GMD and physical security under the umbrella of "all hazards," each is distinct and requires individual consideration.

Talking Points

- Securing and protecting America's critical infrastructure continue to be top priorities for Southern Company and the U.S. electric power industry as a whole. Southern Company is committed to the physical and cyber protection of all critical assets and must focus on the resiliency and redundancy of the electric grid.
- Southern Company continually leverages key partnerships with local and federal agencies – including DOE, DHS, FERC, DOD and others – to better understand and mitigate potential threats including EMP. We also partner closely with other utilities as well as the North American Transmission Forum, EPRI, and EEI to leverage best practices for the protection of the grid's most critical assets.
- Utilities plan for all types of contingencies and have spare equipment available as part of their business continuity planning.
- Since EMP is a potential threat to national security, mitigating the possibility of an EMP incident is primarily the responsibility of the U.S. military and intelligence agencies. While electric utilities and other sectors continue to consider cost-effective protections, the U.S. government's role is critical for broader prevention, protection and defense. Additionally,

information sharing by the U.S. government is critical because most details surrounding EMP risk are classified.

- Broad legislative approaches to protecting the grid, including EMP protections, are premature because:
    - Technically, the actual effect of an EMP event on the bulk power system is still unknown. Southern is actively engaged in EMP-related research activities.
    - There is no “one-size-fits-all” solution to solve all hazards to the electric grid. Solutions must be developed that mitigate specific risks as appropriate.

August 7, 2015

Geomagnetic Disturbances (GMD)

Background

- The potential impact of geomagnetic disturbances (GMD) on the electric system is a topic of ongoing discussion within and beyond the U.S. electric utility industry.
- GMD is basically a "solar storm" that, if severe, has the potential to affect the operation of the electric grid. GMD is a naturally occurring phenomenon initiated by the ejection of an enormous mass of electrically charged particles from the sun (referred to as coronal mass ejection or CME). Not all CMEs are directed towards earth. GMD events occur frequently and generally have no adverse impact to the grid.
- GMD should not be confused with the intense pulse of electromagnetic energy created by either a nuclear or non-nuclear weapon. While GMD events are sometimes referred to as "naturally occurring EMP," the two phenomena are very different from a technical standpoint. Although GMD is often discussed along with EMP and physical security under the umbrella of "all hazards," each is distinct and requires individual consideration.

Talking Points

- Securing and protecting America's critical infrastructure continue to be top priorities for Southern Company and the U.S. electric power industry as a whole. Southern Company is committed to the physical and cyber protection of all critical assets and is focused on the resiliency and redundancy of the electric grid.
- Southern Company continually leverages key partnerships with local and federal agencies – including DOE, DHS, FERC, DOD and others – to better understand and mitigate potential threats. We also partner closely with other utilities as well as the North American Transmission Forum, the Electric Power Research Institute (EPRI), and the Edison Electric Institute (EEI) to leverage best practices for the protection of the grid's most critical assets.
- Southern Company actively participated in the North American Electric Reliability Corporation (NERC) effort to establish mandatory and currently enforceable standards related to GMD.
- An initial assessment indicates that the GMD risk for Southern Company is minimal. Southern Company's geographic location and inherent system resiliency provide significant "natural" mitigation to the potential effects of GMD events.
- Despite the minimal risk across its system, Southern Company continues to focus on evaluating risks from a severe GMD event.
- In addition, Southern Company partners with other utilities to plan for a wide variety of contingencies and has spare equipment available as part of the company's business continuity planning.
- Southern Company is engaging legislators and standard-making bodies to ensure the implementation of cost-effective solutions for our customers. There is no "one-size-fits-all" solution to solve all hazards to the electric grid. Solutions must be developed that mitigate specific risks as appropriate.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

REVISIONS TO RELIABILITY STANDARD FOR TRANSMISSION VEGETATION MANAGEMENT	)))))	**DOCKET NO. RM12-4-000**

COMMENTS OF SOUTHERN COMPANY SERVICES, INC.

Southern Company Services, Inc. ("SCS"), on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively, "Southern Companies"), submits these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") "Revisions to Reliability Standard for Transmission Vegetation Management" Notice of Proposed Rulemaking ("NOPR") issued on October 18, 2012, in the above-referenced docket.[1] In the NOPR, the Commission proposes to approve Reliability Standard FAC-003-2 (Transmission Vegetation Management) ("FAC-003-2") developed and submitted to the Commission for approval by the North American Electric Reliability Organization ("NERC") under Section 215 of the Federal Power Act ("FPA").[2] The Commission also proposes in the NOPR to approve the three new or revised definitions associated with the standard: "Right-of-Way (ROW)," "Vegetation Inspection," and "Minimum Vegetation Clearance Distance (MVCD)," as well as NERC's proposed implementation plan for

---

[1] Revisions to Reliability Standard for Transmission Vegetation Management, Notice of Proposed Rulemaking, 141 FERC ¶ 61,046 (October 18, 2012) (hereinafter, the "NOPR").

[2] See id. at PP 1-3; see also Docket No. RM12-4-000, Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard FAC-003-2 – Transmission Vegetation Management (December 21, 2012) ("Petition"). NERC submitted the Petition in response to certain Commission directives in Order No. 693 approving, among other reliability standards, currently-effective Reliability Standard FAC-003-1 ("Version 1"). See Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

FAC-003-2.[3] Southern Companies generally support the NOPR's proposals and respectfully request that the Commission carefully consider the following comments in connection with any action it might take with respect to FAC-003-2.

I. INTRODUCTION

The Transmission Owners in North America have made great strides in reducing vegetation-related outages under the currently-effective Reliability Standard FAC-003-1 ("FAC-003-1" or "Version 1"). Southern Companies believe that this positive trend will continue under FAC-003-2, in large part, because FAC-003-2 is a better standard than Version 1 and, once approved, more likely to prevent the risk of vegetation-related outages. FAC-003-2 includes numerous changes and modifications developed with substantial stakeholder input and in accordance with NERC's ANSI-approved standards-development process. FAC-003-2 fully satisfies the Commission's directives in Order No. 693 and, if approved, would improve reliability and enforceability.

The Commission has requested comment on several areas pertaining to FAC-003-2 and the information contained in NERC's Petition. To this end, Southern Companies, along with other interested stakeholders, participated in the development of the Edison Electric Institute's ("EEI") comments on the NOPR.[4] Southern Companies support and agree with EEI's comments but are submitting these separate comments in order to provide additional information and comment to the Commission to assist it in its decision-making process.

[3] NOPR at PP 4 and 103.

[4] See Docket No. RM12-4-000, Comments of Edison Electric Institute, et al. (December 20, 2012).

I. REQUIREMENT R1, FOOTNOTE 2

FAC-003-2, Requirement R1 contains a footnote describing certain conditions and scenarios outside the Transmission Owner's control where an encroachment into the MVCD would be exempt from Requirements R1 and R2. Specifically, Requirement R1, footnote 2 provides that:

> This requirement does not apply to circumstances that are beyond the control of the Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.[5]

In its Petition, NERC explains that footnote 2 "…does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to an encroachment that otherwise would not have occurred."[6] The Commission notes NERC's interpretation of footnote 2 in the NOPR and, presumably, agrees with such interpretation.[7] As discussed below, Southern Companies do not agree with NERC's interpretation of footnote 2 and, accordingly, urge the Commission to clearly reject it when acting on the NOPR.

---

[5] FAC-003-2, Requirement R1, footnote 2.

[6] NERC Petition at 23.

[7] See NOPR at P 26.

A. NERC's Interpretation is Inconsistent with the FAC-003-2's Plain Language

NERC's interpretation of footnote 2 is contrary to the footnote's plain language, which, as set forth above, clearly and unambiguously states first that "[Requirement R1] does not apply to circumstances that are beyond the control of the Transmission Owner[.]"[8] Moreover, footnote 2 expressly mentions "human activity" such as the "installation, removal, or digging of vegetation" as an example of circumstances that are beyond the Transmission Owner's control.[9] In this regard, it is difficult (if not impossible) to accept NERC's interpretation of footnote 2, since it is so clearly inconsistent with the standard's plain language and with the intent of the FAC-003-2 Standards Drafting Team ("SDT"), which, as Southern Companies understand it, included footnote 2 in the standard, in part, to maintain the exemption from responsibility for contractor-caused violations provided under Version 1.

B. NERC's Interpretation Would Increase the Risk of Vegetation-Related Outages

NERC's interpretation of footnote 2, if accepted, would give rise to a host of perverse incentives and difficult choices for Transmission Owners. For example, if a Transmission Owner were to identify a tree outside of the ROW that, if felled, would be capable making contact with one of the Transmission Owner's conductors, the Transmission Owner would be required under FAC-003-2 to remove such "danger tree" tree[10] and, most likely, it would use a contractor to perform such removal. And if the Transmission Owner's contractor inadvertently allows the tree to come into contact with the conductor while in the process of removing the tree,

[8] FAC-003-2, Requirement R1, footnote 2.

[9] Id.

[10] Id. at Requirement R6.

under NERC's interpretation of footnote 2, the Transmission Owner would be responsible for such contractor-caused contact and in violation of FAC-003-2. In this situation, the Transmission Owner would be less likely to identify and remove healthy, green danger trees located outside of the ROW, since the Transmission Owner would be responsible for any contractor-caused contact occurring during the removal but not for a contact resulting from the tree falling in from outside the ROW. In this regard, NERC's interpretation of footnote 2, which would discourage Transmission Owners from taking prudent early action to remove danger trees, is contrary to the FAC-003-2's stated purpose of preventing the risk of vegetation-related outages.[11]

II. ENFORCEABILITY-RELATED ISSUES: REQUIREMENT R4

FAC-003-2, Requirement R4 provides as follows:

> Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching for the associated applicable line with the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.[12]

In the NOPR, the Commission raises questions with respect to the phrase "without any intentional time delay" used in Requirement R4. Specifically, the Commission requests comment on how NERC would or should treat a delay in communication caused by the negligence of the Transmission Owner (or one of its employees) where such delay was significant but unintentional.[13]

[11] Id. at Section A.3.

[12] Id. at Requirement R4.

[13] NOPR at P 92.

With respect to the Commission's questions regarding Requirement R4's use of the phrase, "without any intentional time delay", Southern Companies believe that such questions are inherently fact-specific and, thus, more appropriately addressed on a case-by-case basis as part of the NERC and Regional Entity compliance and enforcement processes. Southern Companies also note that, although there was substantial consideration of a specific time-window for notifying the control center of a vegetation-related threat, the phrase "without any intentional time delay" was ultimately adopted because (1) it would avoid the difficulties that otherwise would arise if inspectors were required to report vegetation-related threats within a narrower (and arbitrary) time-window, and (ii) it is a clear "metric" that was already being used and applied to Transmission Owners (and still is) in another Commission-approved reliability standard.[14] Thus, not only does the phrase appropriately balance the need for prompt notification with the practical realities of vegetation management, but NERC and the Regional Entities already have experience interpreting and applying it (and, likewise, Transmission Owners are familiar with its meaning and application) within the compliance and enforcement process.

[14] See TOP-002-2.1b (Normal Operations Planning), Requirements R14, R16, and R17.

III. CONCLUSION

For the reasons stated above, Southern Companies respectfully request that the Commission carefully consider these comments and approve proposed Reliability Standard FAC-003-2, including the associated new and revised definitions and implementation plan, consistent with the positions expressed herein.

Respectfully submitted,

/s/ Drew W. Johnson
Drew W. Johnson
Attorney for Southern Company Services, Inc.

OF COUNSEL

Drew W. Johnson
BALCH & BINGHAM LLP
30 Ivan Allen Jr. Blvd. NW
Suite 700
Atlanta, Georgia 30308-3036
djohnson@balch.com
404.962.3587 (telephone)
866.883.6418 (facsimile)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

	)	
North American Electric Reliability Corporation	)	Docket No. RM12-4

COMMENTS OF THE EDISON ELECTRIC INSTITUTE, AMERICAN PUBLIC POWER ASSOCIATION, LARGE PUBLIC POWER COUNCIL, NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION AND THE TRANSMISSION ACCESS STUDY GROUP

The Edison Electric Institute (EEI), the American Public Power Association (APPA), the Large Public Power Council, the National Rural Electric Cooperative Association (NRECA), and the Transmission Access Policy Study Group (TAPS) (hereinafter referred to as the "Trade Associations") submit the following comments in support of the Commission's Notice of Proposed Rulemaking ("NOPR") to accept proposed reliability standard FAC-003-2, a revised mandatory reliability standard for vegetation management, submitted by the North American Electric Reliability Corporation (NERC). The revised standard provides a complete response to two directives made by the Commission in Order No. 693 and otherwise complies with criteria set by the Commission regarding approval of mandatory reliability standards.[1] The Trade Associations support the Commission proposal. The Trade Associations also provide comments in response to specific issues raised by the Commission in the NOPR.

EEI is the association of the nation's shareholder-owned electric utilities, international affiliates, and industry associates world-wide. EEI member companies are required to comply

[1]*See Mandatory Reliability Standards for the Bulk-Power System,* Order no. 693, FERC Stats. & Regs. ¶31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶61,053 (2007).

with Reliability Standards approved under Section 215 of the FPA, including the proposed revised Vegetation Management Reliability Standard that is the subject of this NOPR.

APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power utilities provide over 15 percent of all kilowatt-hour sales of electricity to ultimate customers, and do business in every state except Hawaii. Collectively, public power systems serve over 46 million customers. Three hundred twenty-eight public power utilities are now included on the NERC compliance registry and are thus directly subject to NERC reliability standards, pursuant to FPA Section 215. One hundred and twelve public power utilities are designated as Transmission Owners.

LPPC represents 25 of the largest state and municipal-owned utilities in the nation. Together, LPPC's members represent 90% of the transmission investment owned by non-federal public power entities.

NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives, including 66 generation and transmission cooperatives that supply wholesale power to their distribution cooperative-owner members.

TAPS is an association of transmission-dependent utilities ("TDUs") in more than 35 states, promoting open and non-discriminatory transmission access.

I. <u>The Trade Associations Support the Commission Proposal to Approve Revised FAC-003 As Mandatory and Enforceable</u>

The Trade Associations strongly believe that the proposed revised standard responds fully to two directives made by the Commission in Order No. 693: to apply FAC-003 to bulk power system transmission lines that have an impact on reliability and to explicitly define in FAC-003 minimum clearance distances that would avoid sustained outages caused by vegetation intrusion. The proposed standard provides a strong defense-in-depth approach to right-of-way ("ROW") vegetation management. As noted by the Commission, the proposed standard now explicitly states minimum clearance distances and the applicability of the standard has been increased to include additional facilities. Moreover, the proposed revised standard includes a requirement for at least an annual inspection.

The Trade Associations agree with the Commission that, if approved, revised FAC-003-2 removes ambiguity and provides greater clarity for utilities who maintain over 180,000 pole-miles of transmission in this country that are subject to NERC's vegetation management reliability standard.[2] As the Commission has noted, the enormous diversity in terrain, vegetation types, growth rates, rainfall, and many other relevant variables introduce significant challenges in designing mandatory requirements that do not impair companies' abilities to tailor their respective vegetation management programs to allow for efficient ROW management in their respective regions. The revised standard FAC-003-2 strikes the appropriate balance between establishing minimum criteria and permitting utility-specific variation that will enhance reliability and prevent outages caused by vegetation intrusion.

II. <u>Comments on Questions Posed in the NOPR</u>

A. Additional Research on the Gallet Equation Should be Limited to Gap Analysis

[2] Source: Statistical Yearbook of the Electric Power Industry, Table 10.6, December 2011, published by Edison Electric Institute.

The Commission seeks comment on its proposal to direct NERC to conduct (or commission) testing and thereafter submit a report to the Commission providing the results of such testing with regard to the use of the Gallet equations in determining minimum vegetation clearance distances ("MVCDs"). (NOPR at P 73) The NOPR acknowledges that the Electric Power Research Institute (EPRI) is likely to begin testing during 2013. The Trade Associations believe that EPRI has the skills and equipment necessary to conduct such work and understands that EPRI is positioned and ready to begin testing in 2013.[3] The Trade Associations support having EPRI independently conduct research, to the extent needed, and submitting at least a preliminary informational report to the Commission with some initial observations by the first quarter of 2014.

The Trade Associations agree that the Commission should seek a clearer understanding of the scope and timeline for the research work, and request an informational filing for this important research activity, either from NERC or EPRI, or as a joint filing. However, the Trade Associations strongly believe that the scope of any such research (and subsequent reporting) that the Commission might require should be limited strictly to validating the "gap factors" used to represent the airgap created between a conductor and vegetation and should <u>not</u> focus on validating or otherwise testing the appropriateness of the Gallet equation itself for use in determining MVCDs. Such validation and testing of the Gallet equation already have taken place and the results are well-documented within the industry.

[3] While the Trade Associations believe that the Commission can rely on EPRI to conduct its work and submit an informational report on a timely basis under this docket, funding the research work may be a challenge. A comprehensive testing program that provides strong analytical results upon which the Commission can rely could involve a considerable amount of money, where the Trade Associations understand that EPRI does not have a dedicated funding source.

As an alternative to the Commission directing NERC to take action, the Trade Associations would ask that the Commission consider conducting informal discussions with NERC and stakeholders to inform decisions on the scope and schedule for such a research project, and how to most effectively ensure strong project management and funding.

B. FERC's Proposed "High" VRF for Requirement 2

In the NOPR, the Commission requests comment on its proposal to increase FAC-003-2 R2's Violation Risk Factor ("VRF") designation to "High" from NERC's recommended "Medium." FERC's proposal would assign to R2 the same VRF as R1 even though R1 specifically addresses higher risk transmission lines (i.e., IROLs and Major WECC Transfer Paths). The Commission seeks to adopt a "High" VRF because "lines that are not designated as an IROL or a Major WECC Transfer path…may still be associated with higher-risk consequences, including outages that can lead to Cascading." (P. 80). The Trade Associations do not disagree with this contention. The test for a "Medium" VRF, however, is not whether a violation *could* lead to system instability, but whether it is *likely* (or unlikely) to occur. (*North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at P 9). The Trade Associations believe that NERC's request for a "Medium" VRF is appropriate because the lines that are neither IROLs nor Major WECC Transfer Paths present a comparatively reduced risk for cascading outages or BES instability. The Trade Associations believe that NERC submitted sufficient documentation to support a "Medium" VRF for R2. It is important that FERC also consider that equating the VRFs for R1 and R2 would defeat the entire purpose of dividing high risk lines in R1 and lower risk lines in R2. The distinction between lines in R1 and R2 received broad industry support and FERC's proposal would have the effect of reversing NERC's and the stakeholder's consensus approach to the development of the FAC-003-2 standard. Thus, the Trade Associations request that FERC retain a "Medium" VRF designation for FAC-003-2 R2.

C. Attaching Technical Guidance Documents

The Commission also seeks comment on the value of attaching a technical and guidance document to the standard as reference material as reference material for utilities. (NOPR at P 91). The Trade Associations agree with the Commission view that such guidance material can have value to inform companies' considerations in developing management plans and activities. At the same time, the Trade Associations caution that such guidance must <u>not</u> alter in any way the mandatory requirements included in a Commission-approved standard or be used as an interpretation of a standard or be used in any way as a compliance measurement. Compliance must be measured <u>only</u> against mandatory requirements and related compliance measures.

D. Reporting Delays

The Commission seeks comment on how NERC might address the obligation in Requirement R4 to notify a relevant control center "without intentional delay" in circumstances where a Transmission Owner identifies a condition that is likely to cause an imminent fault, including circumstances where the delay may be both "significant" and "unintentional." (NOPR at P 92) In addition, the Commission seeks comment on how NERC or the regions might treat a delay in communication caused by negligence, where such delay might be "unintentional."

The Trade Associations believe that in a situation such as the one described by the Commission -- unintentional time delay due to negligence – the Regional Entity compliance team discretion and judgment must reasonably weigh facts and circumstances. An auditor would consider what steps the entity may have already taken as far a disciplinary action or personnel training, or what steps the entity may have taken to address a systemic problem. The Commission's question in the NOPR involving negligence appears to suggest that the proposed standard does not address intentionality, which the proposed standard in fact does. The Trade Associations maintain that such determinations would be fact specific. Moreover, the Trade Associations understand that the Sanctions Guidelines offer latitude for the assessment of penalties, including consideration of aggravating circumstances that may result in higher monetary penalties.

E. "Danger" Timber and ROW Guidance

In the NOPR, the Commission expresses concern that a Transmission Owner may be shielded from enforcement actions by the mere fact that it had a program in place to identify "danger timber," which could include dead, diseased, or dying trees in the area under the Transmission Owner's control (i.e., the legal right-of-way) that could fall through the MVCD. (P 101). The NOPR refers to a data request response made by NERC as the basis for this concern. (P 98). In addition, the Commission seeks comments on how the guidance included in the proposed ROW definition will be used by Transmission Owners in making ROW determinations and by auditors in determining compliance with the proposed Standard.

The Trade Associations agree with what they understand NERC was contending in its data request response, that such a program would satisfy a Transmission Owner's Vegetation Inspection requirements under R6. In other words, in the event of encroachment into the MVCD by a danger tree located outside the ROW, but within the control of the Transmission Owner, that Transmission Owner would not be found in violation of R6 when it implemented a program that regularly identifies danger trees and manages the risk of fall-in encompassing areas within the Transmission Owner's control.

In the NOPR, the Commission also seeks comment on how Transmission Owners will establish criteria to determine its ROW under the proposed definition and by auditors to establish criteria to determine compliance with the proposed ROW definition. The Commission should be aware that the area controlled by a Transmission Owner may often depend on the threshold determinations for ROW boundaries. The Trade Associations understand that for many ROWs, companies may not have construction records, pre-2007 vegetation maintenance records or as-built blowout standards. This would not be unusual given the fact that many transmission lines were constructed decades ago and these guidance materials may no longer be available.

The Trade Associations believe that the Commission should clarify that an individual Transmission Owner may work with NERC and its Regional Entity on a case-by-case basis to discuss a Transmission Owner's approach to ROW determinations when the guiding materials identified in the ROW definition cannot be applied. For example, a Transmission Owner can work with its Regional Entity and NERC in applying recognized procedures established and used by the electric industry. This will ensure that companies will be permitted to obtain the ROW guidance necessary to make their determinations and will provide auditors with the appropriate criteria needed to determine compliance. Inability to define ROW with precision further suggests that in compliance analyses, auditors cannot apply scientifically precise boundary lines with confidence to boundary determinations.

Second, it is common practice to include the identification of and mitigation of "danger timbers" in a Transmission Owner's Vegetation Management Program, but, in many cases the identification of diseased or dying trees is not a matter involving simple observation. The Trade Associations caution the Commission against moving in the direction that an enforcement decision might be based in the future on whether a company had correctly identified a dead or diseased tree, and further, against the use of the term "danger" tree or vegetation as a proxy for well-established terms. Post-hoc analyses of trees should not be needed in order to make a compliance decision. Auditors and companies do not need to debate the differences between "hazard" and "danger" vegetation. Third, on some terrain, it may not be a straightforward matter to determine whether an MVCD encroachment took place.

The Trade Associations share the Commission's concern that companies need to exercise proactive management in their ROW inspections and vegetation management, and that the existence of the management program cannot serve as the basis for a type of compliance immunity. Judging by the enforcement history of FAC-003-1, companies clearly share this view, since there have been only a small handful of violations in five years. On the other hand, the Trade Associations caution the Commission that the variables in play within compliance analyses, especially those considering potential violations involving "danger" trees falling through MVCD, should take place with an understanding that compliance determinations will require estimates in some cases, and that evidence of a strong and proactive ROW vegetation management program might serve as a factor in influencing such determinations. It is imperative that the Transmission Owner has the flexibility to address removal of "danger timbers" without the implication that a utility is obligated to removal all such "danger timbers" if these are outside of the boundaries of the Transmission 'Owner's legally-owned and controlled ROW.

F. Industry Definitions of "Danger" and "Hazard" Trees

In the NOPR, the Commission and NERC use the terms "danger trees" and "danger timber" throughout the discussion of the proposed ROW definition. (NOPR at PP 98, 101). These terms are inconsistent with terminology developed by the American National Institute of Standards ("ANSI"). The ANSI definitions of "Danger Tree" and "Hazard Tree" are standard across the utility industry when discussing trees in the context of vegetation management. ANSI defines a "Danger Tree" as "a tree on or off the right-of-way that could contact electric supply lines." A "Hazard Tree" is defined as "a structurally unsound tree that could strike a target when it fails." (ANSI-A300 - Part 7 American National Standard for Tree Care Operations at §§ 72.5, 72.8). The Trade Associations recommend that the Commission and NERC consider adopting these ANSI terms in future Commission and NERC issuances to avoid confusion among industry participants who already rely on ANSI terminology in their vegetation management practices.

G. Communication of IROL Designations

Proposed standard FAC-003-2 requires that Transmission Owners include lines designated as IROL elements in their respective vegetation management programs. Planning Coordinators are required to designate IROL elements pursuant to the FAC-014 Reliability Standard. In the NOPR, the Commission seeks comment on how IROL status will be transmitted to Transmission Owners. (NOPR at P 64). The Commission correctly notes that Planning Coordinators are not required to notify Transmission Owners of the designation of IROL facilities under the requirements of FAC-014. The Commission requests comment on the potential issues that the lack of a notification structure may create... A vegetation management program is based on the Near Term Planning Horizon. (1-5 years) (NERC Glossary of Terms)

Entities could not document compliance with day to day operating changes to IROLs. This would be a moving target. As a result, the establishment of a clearly defined communication structure and agreed upon start date for compliance documentation prior to Transmission Owners including the IROL elements in their respective vegetation management programs is an important initial step to avoid potentially unnecessary allocations of resources. While clarification may be helpful, the Commission should not hold up approval of FAC-003-2 while this issue is resolved.

III. The Trade Associations Urge the Commission to Demonstrate Leadership on ROW Access Issues

In Docket No. RM06-16-000, EEI raised issues concerning the various problems with ROW access issues, involving especially federal lands. The EEI companies are not alone in these concerns. In 2008, APPA's membership adopted a Policy Resolution urging federal agencies with jurisdiction over property on which electric transmission facilities are located to work cooperatively with the owners and operators of transmission facilities to implement vegetation management procedures and standards for maintaining the reliability of these lines.[4]

In large part, the Trade Associations view the discussions on clearance distances and the application of Gallet equations as symptomatic of this "root cause" ROW access issue. Companies regularly work with private land owners on a broad range of problems and contested challenges for ROW access. These matters are in most cases settled through case-by-case negotiations, or argued under prevailing state law or local ordinances.

In Order No. 693, the Commission declined to endorse the EEI

[4] APPA Resolution 2008-06, Management of Vegetation Surrounding Transmission Lines http://www.publicpower.org/files/PDFs/Resolution08-061.pdf

Memorandum of Understanding (MOU), a document that aimed to directly address the problem of access to federal lands.[5] EEI had envisioned that a Commission endorsement of the MOU might offer some leverage in cases where federal agency personnel challenged or rejected requests for access, or imposed unreasonable or impractical conditions. Instead, the Commission critiqued the IEEE standard embedded in the EEI MOU as suggesting a too conservative approach for determining minimum clearances, and directed NERC to include explicitly stated minimum clearance distances in the revised standard.

The design intention of the EEI MOU was not to define minimum clearances *per se*, but rather to convey a strong sense of urgency to various federal personnel who authorize access. The ROW access issue remains a very serious matter and continues to need both the attention and involvement of agency leadership and a push for effective "no regrets" solutions.

The Trade Associations and their member companies have engaged the federal lands ROW access issue in good faith for several years as part of a coalition in search of practical remedies. For some companies the access issue is a significant variable in setting facilities ratings, configuring transmission for reliability, and scheduling and performing necessary and time-sensitive repair and maintenance work, as well as for vegetation management. Federal agencies that play significant roles include primarily the Forest Service and the Bureau of Land Management ("BLM"). Especially in the western states, companies have experienced significant difficulties with Forest Service and BLM field personnel for obtaining both timely permission to

---

[5]Memorandum of Understanding Among The Edison Electric Institute and the U.S. Department of Agriculture Forest Service and the U.S. Department of the Interior, Bureau of Land Management, Fish and Wildlife Service, National Park Service and the U.S. Environmental Protection Agency, 2006 ("EEI MOU").

access various lands, and for scheduling facilities inspections and maintenance activities, including vegetation management.

The Trade Associations therefore urge the Commission to initiate and coordinate discussions with other federal agencies, and to work cooperatively with stakeholder groups, in an effort to find practical remedies to the ROW access issues that balance the broad range of policy and management objectives, and to work to a defined timetable for successful outcomes.[6] The Trade Associations stand ready to begin this important work as soon as possible, including possible revisions to the EEI MOU.

IV. Transmission Owners Employ Vegetation Management Best Practices

Since FAC-003-1 was approved by the Commission and implemented, companies have aggressively pursued compliance under a "zero defects" mandate for transmission tree-related outages. NERC has utilized compliance audits, spot checks, periodic reporting and annual self-certifications, along with investigation of self-reports of potential violations. As a result, there have been only a very small number of violations that have affected the reliable operation of the bulk power system.

As noted by Chairman Wellinghoff's statement in June 2012 "environmental issues, property rights and cost, among other things, continue to play an important role in every company's vegetation management program." At such time that the Commission approves FAC-003-2, it is imperative that Transmission Owners get the full support of the Commission to

[6] Related to the "access" issue is the issue of environmental requirements that prevent or hinder trimming and cutting activity on federal lands and EEI believes that this should be addressed as part of the overall solution to the ROW access issue.

execute transmission vegetation management programs that will assure zero encroachment of vegetation to prevent those vegetation-related outages that could lead to cascading outages.

Transmission Owners understand the importance of property owner notice and generally have detailed notification procedures in place to engage property owners in a timely and forthright manner. As it is the sole responsibility of the Transmission Owners to implement a transmission vegetation management program that will meet a zero tolerance standard for vegetation encroachment, the attempt to minimize the impact to property owners, can only be offered, to the extent possible, where safety and reliability will not be sacrificed.

Transmission Owners' vegetation management practices are designed to prevent vegetation related outages by creating and sustaining a stable and compatible vegetated community within and along the transmission corridor using integrated vegetation management techniques. Incorporating integrated vegetation management (IVM) techniques, involves evaluating the transmission corridor to identify incompatible vegetation, defining timeframe for control, and evaluation and selection of control options. IVM control options include manual, mechanical, cultural, and chemical methods that are used to prevent outages from vegetation located on and adjacent to transmission corridors. The choice of control options considers site characteristics, environmental impact, and worker/public safety. The goal of using IVM techniques is to create and sustain a stable and compatible vegetated community within and along the transmission corridor.

Transmission Owners also must make determinations to employ IVM techniques where vegetation that may interfere or threatens to interfere with the safe and reliability operation of transmission facilities to employ IVM techniques. Vegetation that has the genetic disposition to grow to heights that may interfere with transmission should be removed., As utility vegetation management programs proven over time, continuous trimming will not guarantee or assure zero encroachment, and it is a gamble or roll of the dice not to use best management practice and remove or apply a herbicide to vegetation that will interfere with transmission based on the vegetation's genetic disposition.

Transmission Owners do have successful vegetation management programs that also help property owners maintain and even enhance the environmental benefits and aesthetics of the right-of-way while ensuring sufficient clearance between the vegetation and energized conductors. Educational information through websites, brochures and on-site meetings with property owners has been used by Transmission Owners to address a variety of questions and concerns.

Often times the implementation of vegetation management practices require educating property owners regarding what utility easement rights Transmission Owners holds and the requirements of the utility's transmission vegetation management program requirements. These are the means that Transmission Owners are striving to use to address incompatible vegetation on rights-of-way rather than purporting that the clear-cutting of rights-of-way is required in order to comply with reliability standard FAC-003.

While in today's society people are accustomed to having information readily available on the Internet, there are a variety of means that Transmission Owners use to communicate their transmission vegetation management activities that are specific to property owners. The formal transmission vegetation management plan and an annual plan for vegetation management work that the current reliability standard FAC-003 requires can be complex and at a higher level than the specific property owner. Transmission Owners continue to strive to utilize proactive communication tools which may include posting information on their website.

V. Conclusion

The Trade Associations respectfully request that the Commission consider these comments and approve proposed reliability standard FAC-003-2.

Respectfully submitted,

/s/________________________

EDISON ELECTRIC INSTITUTE

James P. Fama
Vice President, Energy Delivery
Barbara A. Hindin
Associate General Counsel
701 Pennsylvania Ave., NW
Washington, DC 20004
202-508-5000

AMERICAN PUBLIC POWER ASSOCIATION

Allen Mosher
Vice President of Policy Analysis and Reliability Standards
1875 Connecticut Ave., NW
Suite 1200
Washington, DC 2009
202-467-2900

LARGE PUBLIC POWER COUNCIL
Jonathan D. Schneider
Jon Trotta
STINSON MORRISON HECKER LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036-3816
202-785-9100

Counsel for Large Public Power Council

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

Richard Meyer
Senior Regulatory Counsel
Patricia Metro
Manager, Transmission & Reliability Standards
4301 Wilson Boulevard
Arlington, VA 22203-1860
703-907-5811

TRANSMISSION ACCESS POLICY STUDY GROUP
Cynthia S. Bogorad
Rebecca J. Baldwin
SPIEGEL &MCDIARMID LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036
(202) 879-4000

Counsel for Transmission Access Policy Study Group

December 20, 2012

TO: State Regulatory Commissioners - NARUC Summer Committee Meetings

SUBJECT: KEY POLICY ISSUES

There are many issues that will be addressed at the NARUC Summer Committee Meetings in Los Angeles, California. This letter and attached materials highlight those issues.

U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA) - Tab 1

The electric power industry faces an unprecedented number of new environmental regulations over the next several years and is moving forward with multi-billion dollar investments to modernize the generation fleet and the electric grid. Included in this tab is a timeline of environmental regulatory requirements; a chart that highlights the industry's emission reductions; a listing of coal units by age, capacity and emissions; and a summary of coal fleet retirement announcements by electric utilities.

In addition, this tab includes a policy brief on the impact of proposed 316(b) regulations that will require changes in power plant cooling water systems and a map identifying the power plants that will be affected by EPA's proposed rule. The proposed rule may have substantial economic, energy, and environmental impact on electric generating and manufacturing facilities nationwide, without providing corresponding benefits.

CARBON CAPTURE AND STORAGE (CCS) - Tab 2

CCS is a promising and important technology that will allow continued utilization of our abundant domestic coal reserves to generate a reliable and affordable supply of electricity in a cleaner manner. CCS commercialization is still in the future, but demonstration technologies hold great promise. This tab includes an overview of key players and issues, and a chart that tracks CCS state legislative activities.

CYBER SECURITY & INFRASTRUCTURE RELIABILITY - Tab 3

Protecting the nation's electric grid and ensuring a reliable, affordable supply of power is the electric power industry's top priority. Indeed, system reliability requirements are what set electric utilities apart from most other industries. Utilities have an obligation to serve, to maintain exceptional reliability, and to keep their systems secure in an era of increasing cyber threats.

This tab includes an issue overview and EEI's principles on cyber security and a side-by-side comparison of cyber security legislation. Also included in this tab, are the testimonies of EEI Executive Vice President David Owens and Sandia National Laboratories Senior Scientist Dr. William Tedeschi before the U.S. Senate Committee on Energy and Natural Resources in May 2011. Other witnesses included Gerry Cauley, President and CEO of the North American Electric Reliability Corporation (NERC), Joseph H. McClellan, Director, Office of Electric Reliability at the Federal Energy Regulatory Commission (FERC) and The Honorable Patricia Hoffman, Assistant Secretary for the Office of Electricity Delivery, U.S. Department of Energy. Finally, this tab includes a letter from NERC on the impacts of geomagnetic disturbances (GMD) on the grid, and a NERC advisory on GMD.

INFRASTRUCTURE INVESTMENTS AND NEW REGULATORY FRAMEWORKS - Tab 4

Electric utilities and their customers face significant financial challenges in the years ahead. Utilities will need to raise and invest large amounts of new capital to rebuild the nation's electricity infrastructure to maintain and improve reliability and service quality. This will require potentially doubling or even tripling the existing asset base over the next 20 years.

There will also be the need to raise and invest new capital to make non-traditional investments in energy efficiency, emerging technologies and environmental infrastructure to meet public policy goals and requirements. These investments are being made in a era of slowing energy usage and uncertainty about a national energy policy.

Included in this tab is an EEI issue brief listing regulatory tools for state consideration and a state-by-state matrix identifying innovative regulatory approaches which facilitates infrastructure investments and mitigates rate shock on consumers.

PLUG-IN ELECTRIC VEHICLES (PEVs) - Tab 5
The transformation of the nation's transportation fleet to one fueled in part by domestically produced electricity can gradually help reduce our dependence on foreign energy sources. PEVs are being rolled out in major U.S. markets, as automobile manufacturers join utilities in embracing electricity as an important transportation fuel.

Included in this tab is a chart comparing monthly motor gasoline prices to monthly electricity prices, a guide to the new EPA/Department of Transportation fuel economy labels, and an EEI PEV issue brief.

DODD-FRANK IMPLEMENTATION - Tab 6
Included in this tab is an issue paper that highlights concerns with the Commodity Futures Trading Commission's (CFTC) implementation of the Dodd-Frank Financial Reform Act that was signed into law in 2010. There is a concern that electric utilities are being mischaracterized as swap dealers and this would result in extensive regulatory requirements and costly reporting obligations that will increase electric bills and reduce the capital available for needed utility infrastructure enhancements.

INTEGRATION OF VARIABLE ENERGY RESOURCES - Tab 7
Included in this tab is an issue brief that highlights EEI's support for regional flexibility as the Federal Energy Regulatory Commission (FERC) addresses the issue of reliably and efficiently integrating variable energy resources.

POLE ATTACHMENTS - Tab 8
This tab includes a summary of the U.S. Federal Communications Commission's (FCC) rules on access to the communication space on utility poles, enforcement processes and pole rental rates.

INSTITUTE FOR ELECTRIC EFFICIENCY (IEE) - Tab 9
Included in this tab is an invitation to attend an IEE breakfast briefing on new lighting standards. The briefing will be on Wednesday, July 20 at 7:00 a.m. in the Plaza I & II located on the 3rd floor of the JW Marriott. Breakfast will be served at 6:30 a.m.

Also included in this tab, is an abstract of the recently released IEE whitepaper paper entitled "Assessment of Electricity Savings in the U.S. Achievable through New Appliance/Equipment Efficiency Standards and Building Codes (2010-2025)."

Finally, this tab includes the June 2010 IEE State Electric Efficiency Regulatory Frameworks report.

CONCLUSION

As highlighted in this email and attachments, there are many significant issues for state regulatory commissioners and utilities to consider. We hope you find these background materials helpful in your important deliberations and participation in the NARUC Summer Committee Meetings.

Finally, we invite you to join us on Tuesday, July 19, at 5:15 p.m. in the Platinum Ballroom Salons H-J located on the 2nd floor of the JW Marriott Hotel for the EEI reception.