UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD EOP-010-1 – GEOMAGNETIC DISTURBANCE OPERATIONS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard EOP-010-1 for Commission approval. NERC requests that the Commission approve proposed Reliability Standard EOP-010-1 (**Exhibit A**) and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**), Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit F**), as detailed in this petition.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard EOP-010-1, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order

1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

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

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

5 18 C.F.R. § 39.5(a) (2013).

No. 672[6] (**Exhibit C**) and a summary of the development history (**Exhibit H**). Proposed Reliability Standard EOP-010-1 was approved by the NERC Board of Trustees on November 7, 2013.

I. EXECUTIVE SUMMARY

Geomagnetic disturbances ("GMD") occur when solar storms on the sun's surface send electrically charged particles toward earth, where they interact with the earth's magnetic field. Proposed Reliability Standard EOP-010-1—Geomagnetic Disturbance Operations would be a new Reliability Standard that attempts to mitigate the effects of GMD events by implementing Operating Plans,[7] Operating Processes,[8] and Operating Procedures[9] and is responsive to Commission concerns in Order No. 779.[10]

In Order No. 779, the Commission directed the development of Reliability Standards to address GMDs in two stages.[11] In the first stage, the subject of this petition, NERC is submitting proposed Reliability Standard EOP-010-1, requiring owners and operators of the Bulk-Power System to develop and implement Operational Procedures to mitigate the effects of GMDs

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

7 An "Operating Plan" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan." *Available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

8 The term "Operating Procedure" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure." *Available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

9 The term "Operating Process" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process." *Available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

10 *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013)("Order No. 779").

11 *Id.*

consistent with the reliable operation of the Bulk-Power System. The second stage of Reliability Standards to address GMDs, currently under development, requires NERC to develop proposed Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.[12]

During a severe GMD event, geomagnetically-induced current ("GIC") flow in transformers (resulting in half-cycle saturation) can substantially increase absorption of reactive power, create harmonics, and, in some cases, cause transformer hot-spot heating, which could lead to loss of Reactive Power support-- thereby causing voltage instability, protective relay Misoperations and potential equipment loss-of-life or damage. As a high-impact, low-frequency event, GMDs pose a unique threat to Bulk-Power System reliability, and the proposed Reliability Standard is intended to lessen the impact of such events.

As the Commission noted in Order No. 779, "[o]perational procedures may help alleviate abnormal system conditions due to transformer absorption of reactive power during GMD events, helping to stabilize system voltage swings, and may potentially isolate some equipment from being damaged or misoperated."[13] The proposed Reliability Standard allows entities to tailor their Operating Plans, Processes and Procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology. The coordination of the Operating Plans, Processes and Procedures would be overseen by the Reliability Coordinator, consistent with its wide-area perspective.

The proposed Reliability Standard is an important first step in addressing the issue of GMDs and can be implemented relatively quickly. While responsible entities will develop and

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

[13] *Id.* at P 36.

implement Operational Procedures or Operational Processes, NERC will continue to support those efforts through the GMD Task Force, for example, by identifying and sharing Operating Plans, Processes, and Procedures found to be the most effective.

NERC requests that the Commission approve proposed Reliability Standard EOP-010-1 and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[14]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[15] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and

[14] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

[15] 16 U.S.C. § 824o (2006).

enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[16] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[17] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[18] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[19] and Section 39.5(c)[20] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Process

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[21] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards

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16 *Id.* § 824(b)(1).

17 *Id.* § 824o(d)(5).

18 18 C.F.R. § 39.5(a) (2012).

19 16 U.S.C. § 824o(d)(2).

20 18 C.F.R. § 39.5(c)(1).

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

Development) of its Rules of Procedure and the NERC Standard Processes Manual.[22] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[23] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. Technical Background: Geomagnetic Disturbances

A GMD is caused by solar events resulting in distortions of the earth's magnetic field, and can be of varying intensity. The science regarding the impacts of GMDs on electric power systems is still in the developmental stages and much remains to be learned about the unique threat GMDs pose to reliability. The characteristics of GMDs (*e.g.*, the peak and duration of induced geo-electric fields) experienced by the power system is dependent on a number of factors, including where the geomagnetic storm is centered, the direction of the fields along with their polarity, geomagnetic latitude, and the geology (electrical conductivity of the ground). As the Commission noted in Order No. 779, "while there is an ongoing debate as to how a severe GMD event will most likely impact the Bulk-Power System, there is a general consensus that GMD events can cause wide-spread blackouts due to voltage instability and subsequent voltage collapse, thus disrupting the reliable operation of the Bulk-Power System."[24]

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

23 116 FERC ¶ 61,062 at P 250 (2006).

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

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

In June 2010, NERC identified that GMDs were a serious threat to the reliable operation of the Bulk-Power System and that this issue required significant staff and industry attention with close monitoring of progress. Since that time, NERC has spent a substantial amount of time and effort working with experts across the North American power industry, U.S. and Canadian government agencies, transformer manufacturers, and other vendors, in developing scientifically sound and repeatable conclusions.

In early 2011, a NERC-sponsored GMD Task Force was formed to "develop a technical white paper describing the evaluation of scenarios of potential GMD impacts, identifying key bulk power system parameters under those scenario conditions, and evaluating potential reliability implications of these incidents."[25] The resulting report, the NERC Interim GMD Report evaluating the effects of GMDs on the Bulk-Power System, was issued in February 2012.[26]

In October 2012, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to direct that NERC submit to the Commission for approval proposed Reliability Standards that address the risks posed by GMDs to the reliable operation of the Bulk-Power System.[27] The NOPR stated that GMD vulnerabilities are not adequately addressed in the existing Reliability Standards and that this constitutes a reliability gap because GMD events can cause the Bulk-Power System to collapse suddenly and can potentially damage equipment on the

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

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

[27] *Reliability Standards for Geomagnetic Disturbances*, Notice of Proposed Rulemaking, 77 FR 64,935 (Oct. 24, 2012), 141 FERC ¶ 61,045 (2012) ("NOPR").

Bulk-Power System.[28] In May 2013, the Commission issued Order No. 779 directing NERC to develop proposed Reliability Standards addressing GMD events in two stages, as explained herein.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in **Exhibit C**, proposed Reliability Standard EOP-010-1--Geomagnetic Disturbance Operations satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The purpose of proposed Reliability Standard EOP-010-1 is to mitigate the reliability impacts of GMD events by implementing Operating Plans, Processes, and Procedures. Provided below is an explanation of the applicability of the proposed Reliability Standard and a justification on a Requirement-by-Requirement basis.

A. Applicability of EOP-010-1 – Geomagnetic Disturbance Operations

The proposed Reliability Standard is applicable to: (1) Transmission Operators with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV, and (2) Reliability Coordinators.[29] This applicability is consistent with Order No. 779 and the NERC Functional Model.

As the Commission noted in Order No. 779, "[b]ecause many Bulk-Power System transformers are grounded, the GIC appears as electrical current to the Bulk-Power System and flows through the ground connection and conductors, such as transformers and transmission lines."[30] The applicability of proposed Reliability Standard EOP-010-1 recognizes the technical considerations of the impact of a GMD on the Bulk-Power System.

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[28] *Id.* at P 4.

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

[30] Order No. 779 at P 6 citing North American Electric Reliability Corp., *2012 Special Reliability Assessment*

The NERC Functional Model is structured to ensure that there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System.[31] A Reliability Coordinator has responsibility and authority for reliable operation within the Reliability Coordinator Area. A Reliability Coordinator's scope includes a wide-area view with situational awareness of neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

Like the Reliability Coordinator, the Transmission Operator has responsibility and authority for the reliable operation of the transmission system within a specified area. The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

Together, the inclusion of these two functional entities— Reliability Coordinators and Transmission Operators— in proposed Reliability Standard EOP-010-1, provides for the development and implementation of Operational Procedures and coordination across regions.[32]

Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at ii (February 2012) (*NERC Interim GMD Report*), *available at* http://www.nerc.com/files/2012GMD.pdf.

[31] The NERC Reliability Functional Model is available at: http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf

[32] The NERC Functional Model describes the relationships between functional entities in performing their reliability related tasks. The Reliability Coordinator "Coordinates with Transmission Operators on system restoration plans, contingency plans, and reliability-related services" ahead of time, and " Issues corrective actions and emergency procedures directives to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators" in real time.
Available at:
http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf
See also, **Exhibit E**.

As explained in **Exhibit D**, the applicability threshold of greater than 200 kV is based on analysis by the standard drafting team. There are several key parameters in assessing the impacts of a GMD, including:

- Transformer grounding and core construction;
- System topology;
- Geographic location;
- Resistance values of the elements of the DC network used to evaluate GIC distribution within the network.

Based on an analysis of these factors, the standard drafting team determined that a voltage threshold of greater than 200 kV is appropriate. This finding is supported by operating experience and the preponderance of peer-reviewed studies on GMD effects.[33] Further, the standard drafting team determined that the effect of GIC in networks less than 200 kV has negligible impact on the reliability of the interconnected transmission system. Therefore, as noted above, the applicability of proposed Reliability Standard EOP-010-1 also recognizes the technical considerations of the impact of a GMD on the Bulk-Power System.

B. Requirements in EOP-010-1 – Geomagnetic Disturbance Operations

The proposed Reliability Standard consists of three Requirements. Requirement R1 addresses coordination within a Reliability Coordinator Area. Requirement R2 addresses the dissemination of space weather information to ensure that entities within a Reliability Coordinator Area have the appropriate information necessary to take action and that the same information is available to all entities. Requirement R3 requires the development of GMD Operating Procedures or Processes. Collectively, these Requirements satisfy the Commission's

[33] *See* **Exhibit D**.

directives in Order No. 779 and are intended to mitigate the effects of GMD events through the implementation of Operating Plans, Processes, and Procedures.

Proposed Requirements

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area.

Requirement R1 of proposed Reliability Standard EOP-010-1 requires several actions from Reliability Coordinators: development, maintenance, and implementation of a GMD Operating Plan, as well as coordination. An Operating Plan is *maintained* when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose. An Operating Plan is *implemented* by carrying out its stated actions. The *coordination* is intended to ensure that Operating Procedures and Operating Processes within a Reliability Coordinator Area[34] are not in conflict with one another; it is *not* intended to be a review by the Reliability Coordinator of the technical aspects of the GMD Operating Procedures or Processes. Transmission Operators are responsible for the technical integrity of their Operating Procedures or Processes pursuant to Requirement R3. For example, if Company A submitted an Operating Procedure proposing to take Line X out of service under specified GMD conditions, and Company B submitted an Operating Procedure that relies on Line X remaining in service in the event of a GMD -- it is the responsibility of the Reliability

[34] The term "Reliability Coordinator Area" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas." *Available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

Coordinator to *identify* this conflict. The Reliability Coordinator could then require Company A and Company B to resolve this conflict and resubmit their Operating Procedures.

Part 1.1 of Requirement R1 requires Reliability Coordinators to describe the activities that must be undertaken in order to mitigate the effects of a GMD. Those activities could require a Balancing Authority to take action. Pursuant to IRO-001, the Reliability Coordinator has clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. Part 1.2 of Requirement R1 requires Reliability Coordinators to establish a process to review the GMD Operating Procedures or Operating Processes of the Transmission Operators in the Reliability Coordinator Area

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.

Requirement R2 of proposed Reliability Standard EOP-010-1 addresses the dissemination of space weather information; such information can be used for situational awareness and safe posturing of the system. Space weather information can also be used for monitoring the progress of a GMD event. As the entity with a wide-area view, the Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Requirement R2 of proposed Reliability Standard EOP-010-1 replaces IRO-005-3.1a, Requirement R3. IRO-005- 3.1a, Requirement R3 states:

> Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

Reliability Standard IRO-005-4, which addresses reliability coordination for current day operations, has been adopted by the NERC Board and filed with the Commission, and would retire IRO-005-3.1a , Requirement R3.[35] Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, if proposed Reliability Standard EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 of EOP-010-1 shall become effective on the first day following retirement of IRO-005-3.1a as detailed in **Exhibit B**.

R3. Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Process shall include:

3.1. Steps or tasks to receive space weather information.
3.2. System Operator actions to be initiated based on predetermined conditions.
3.3. The conditions for terminating the Operating Procedure or Operating Process.

Requirement R3 of proposed Reliability Standard EOP-010-1 requires Transmission Operators to develop Operating Procedures or Operating Processes to address GMD events. Similar to Requirement R1, an Operating Procedure or Operating Process is *implemented* by carrying out its stated actions. An Operating Procedure or Operating Process is *maintained* when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose. Requirement R3 is not prescriptive and allows

[35] Reliability Standard IRO-005-4 provides:

Requirement R1. When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.

Requirement R2. Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated.

entities to tailor their Operational Procedures or Processes based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology. This approach is consistent with the development of results-based Reliability Standards.[36] As the Commission noted in Order No. 779, owners and operators of the Bulk-Power System are most familiar with their own equipment and system configurations.[37]

Part 3.1 of Requirement R3 requires Transmission Operators to specify in their Operating Procedures or Processes steps or tasks that must be conducted to receive space weather information. Part 3.2 of Requirement R3 requires Transmission Operators to specify what actions must be taken under what conditions and such conditions must be predetermined. Part 3.3 of Requirement R3 requires Transmission Operators to specify when and under what conditions the Operating Procedure or Process is exited. For example, if an Operating Procedure specifies that certain actions must be taken when a space weather alert is received, the Operating Procedure should specify when such actions would be terminated. Collectively, these Parts of Requirement R3 ensure that there is a baseline level of detail in the Operating Procedures or Processes while maintaining necessary flexibility in order to allow responsible entities to tailor their Operating Procedures or Processes as needed. Furthermore, the proposed Reliability Standard is technology neutral.

Proposed Reliability Standard EOP-010-1 does not prescribe specific actions that must be taken by responsible entities because a "one-size fits all" approach to crafting GMD Reliability Standards would fail to recognize the important role of locational differences.[38] Indeed, the

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[36] Results-based Reliability Standards focus on required actions or results and not necessarily the methods by which those actions or results must be accomplished.

[37] Order No. 779 at P 38.

[38] As Commissioner LaFleur has noted, the panelists at the April 30, 2012 FERC technical conference agreed that "there can be considerable differences in GMD exposure and impacts depending on geography, where you are in the earth, ground conditions, grid configuration, and equipment condition…" *See* Electric Infrastructure Security Summit III, London, May 14-15, 2012, The House of Parliament, United Kingdom at p. 25.

Commission stated in Order No. 779 that it "do[es] not expect that owners and operators of the Bulk-Power System will necessarily develop and implement the *same* operational procedures."[39] The standard drafting team determined that the variability in the impacts of GMD precludes the development of prescriptive requirements.[40]

For these reasons, the proposed Reliability Standard is just and reasonable and should mitigate the effects of GMD events through the implementation of Operating Plans, Processes, and Procedures.

C. Commission Directives Addressed

As explained in **Exhibit G**, the proposed Reliability Standard satisfies all of the Commission's directives in Order No. 779 with respect to Stage 1 of the GMD Reliability Standards. Requirements R1 and R3 of proposed Reliability Standard EOP-010-1 satisfy the Commission's directive to submit "within six months of the effective date of this Final Rule, one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System."[41] Requirement R1 requires Reliability Coordinators to develop, maintain and implement a GMD Operating Plan that coordinates GMD Operating Procedures within its Reliability Coordinator Area. Requirement R3 requires Transmission Operators to develop, maintain, and implement an Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. Order No. 779 became effective on July 22, 2013 and the instant petition is being submitted within six months, in compliance with the Commission's directive. The

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[39] Order No. 779 at P 38 (emphasis added).

[40] *See* Consideration of Comments: Project 2013-03 (August 30, 2013) at p. 37.

[41] Order No. 779 at P 30.

proposed Reliability Standard satisfies the Commission's directives and also addresses the Commission's concerns regarding the need for flexibility in Operational Procedures.

D. Enforceability of EOP-010-1

The proposed Reliability Standard includes Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit F**.

The proposed Reliability Standard also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[42]

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

V. <u>CONCLUSION</u>

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

- approve the proposed Reliability Standard and associated elements included in **Exhibit A,** effective as proposed herein;

- approve the implementation plan included in **Exhibit B** as proposed herein.

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

Date: November 14, 2013

Exhibit A

Proposed Reliability Standard

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**

2. **Number:** EOP-010-1

3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator
   4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Protection System Misoperation, the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

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

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area.

M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

R3. Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. Steps or tasks to receive space weather information.

3.2. System Operator actions to be initiated based on predetermined conditions.

3.3. The conditions for terminating the Operating Procedure or Operating Process.

M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator and Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations Planning,	Medium	The Transmission Operator had a GMD Operating Procedure or Operating Process,	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator did not have a GMD Operating Procedure or Operating

	Same-day Operations, Real-time Operations		but failed to maintain it.	failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

D. Regional Variances

None.

E. Interpretations

None.

F. Guideline and Technical Basis

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

Rationale for R1:

An Operating Plan is implemented by carrying out its stated actions.

Coordination is intended to ensure that Operating Procedures are not in conflict with one another. An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

Rationale for R2:

Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Rationale for R3:

In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Version History

Version	Date	Action	Change Tracking
1	11/07/2013	Adopted by the NERC Board of Trustees	

Exhibit B

Implementation Plan

NERC
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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator

Transmission Operator with a Transmission Operator Area that includes any transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

Requirement R2 of EOP-010-1 replaces Requirement R3 of IRO-005-3.1a. IRO-005-4 has been adopted by the NERC Board and filed with FERC in Docket Number RM13-15-000, and will retire Requirement R3 of IRO-005-3.1a:

> **IRO-005-3.1a, Requirement R3:**
>
> **R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

EOP-010-1 replaces this requirement with the following:

> **EOP-010-1, Requirement R2:**
>
> **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.

Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, EOP-010-1 shall become effective as follows:

In jurisdictions where regulatory approval is required:

- The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in that jurisdiction.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

In jurisdictions where regulatory approval is not required:

- The first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Exhibit C

Order No. 672 Criteria

Exhibit C -- Order No. 672 Criteria

Order No. 672 Criteria

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

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

Proposed Reliability Standard EOP-010-1 achieves the specific reliability goal of mitigating the effects of geomagnetic disturbance ("GMD") events on the Bulk-Power System. Such events pose a unique threat to reliability and the proposed Reliability Standard will lessen their impact by requiring the development of Operating Plans, Operating Procedures, and Operating Processes for use in anticipation of, and during, GMD events. Operating Plans, Procedures, and Processes will be developed with the goal of stabilizing system voltage swings and isolating equipment that may be vulnerable to damage or Misoperation during the course of

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

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

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

a GMD event. While entities have flexibility in developing individual plans based on several factors, the Reliability Coordinator will ensure proper coordination between responsible entities during development, maintenance, and implementation.

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to the Reliability Coordinators and Transmission Operators with Transmission Operator Areas that include any power transformer with a high side wye-grounded winding with a terminal voltage greater than 200 kV. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar

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

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

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

violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner. [5]

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. The Measures are as follows:

> M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.
>
> M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.
>
> M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

These measures help provide clarity regarding how the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]**

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. Responsible entities have flexibility in developing individual Operating Plans, Operating Procedures, and Operating Processes. Several factors unique to each entity may be considered during development, including geography, geology, and system topology.

6. **Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]**

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant reliability benefits for the Bulk-Power System. The provisions of the proposed Reliability Standard raise the level of preparedness among responsible entities by requiring the development, maintenance, and implementation of Operating Plans, Operating Procedures, and Operating Processes designed to mitigate the potentially severe impacts of a GMD on the Bulk-Power System.

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

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

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

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

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

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

Proposed Reliability Standard EOP-010-1 has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities in the development of Operating Plans, Operating Processes, and Operating Procedures.

The proposed Reliability Standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner. The Requirements in the proposed Reliability Standard are designed to meet important reliability goals in the event of a GMD—an event that poses a unique threat to the Bulk-Power System—

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

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

before, during, and after the event. Responsible entities are able to develop their own plans to ensure those goals can be met.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the standard are just and reasonable and appropriately balance the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the Requirements. The proposed effective date is explained in the proposed implementation plan, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit H** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team

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

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

were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

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

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

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

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

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

Exhibit D

White Paper Supporting Network Applicability

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Network Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators and Transmission Operators with networks that contain power transformers with high side grounded wye windings above 200 kV. The drafting team concluded that this is the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. This lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature, as explained below.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779.

Justification

Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (115 kV lines are typically less than 15 miles in length), the resulting geomagnetically-induced current (GIC) generated by lines rated less than 200 kV are significantly less than those of higher voltages and are typically ignored in GIC analysis. Conversely, using a voltage threshold higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap by excluding a portion of the network that can be significantly affected by GMD. Results of sensitivity analysis conducted by the drafting team are presented in the appendix. It shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event.

Network Definition Considerations

Key parameters in the definition of a network for assessing GMD impacts are:

- Transformer grounding and core construction
  - Only wye-grounded power transformer windings provide a path for GIC
  - Transformer core construction (e.g., single-phase, three-phase, autotransformer) has an effect on the magnitude of var absorption and generated harmonics. Single-phase transformers are more susceptible to half-cycle saturation due to GIC relative to three-phase 3-leg units; however, the var absorption in 3-legged three-phase core units cannot be neglected.
  - Regardless of core construction, all grounded wye transformers have an effect in the distribution of GIC in the network
- System topology
- Geographical location
- Resistance values of the elements of the DC network used to evaluate GIC distribution within the network
  - Transmission line resistances per unit length increase as the voltage level decreases (see typical values in Table 1). (With the resistances shown in Table 1, the maximum neutral GIC contributed by a single 230 kV circuit is of the order of 30 A, as opposed to 75 A for a single 345 kV circuit.)

Selection of a network where the cut off is selected on the basis of wye-grounded power transformers with HV terminals > 200 kV

- Almost all peer-reviewed studies on the effects of GIC include networks > 200 kV [1-13].
- When lower voltage levels are included, the effects of including network elements < 200 kV are in most cases minimal [9]. (The Appendix shows an example of the effects of the inclusion/exclusion of the 115 kV network.)
- The absorption of reactive power in a saturated transformer depends on the system operating voltage and GIC. It does not depend on the nameplate rating of the transformer. In the case of single-phase power transformers, var absorption and harmonic generation are very insensitive to air-core reactance [11].

TABLE 1

TYPICAL NETWORK RESISTANCES FOR DIFFERENT VOLTAGE-LEVEL POWER GRIDS IN NORTH AMERICA

System Voltage Levels (kV)	DC Resistances of the Transformers (ohm)	Grounding Resistances of the Substations (ohm)	DC Resistances of the Transmission lines (ohm/km)
230	0.692	0.563	0.072
345	0.356	0.667	0.037
500	0.195	0.125	0.013
735	0.159	0.258	0.011

- Reactive power absorption of a saturated transformer is proportional to its HV voltage rating. Transformers < 200 kV have a relatively lower influence in the reactive power balance of the system (see Figure 1).

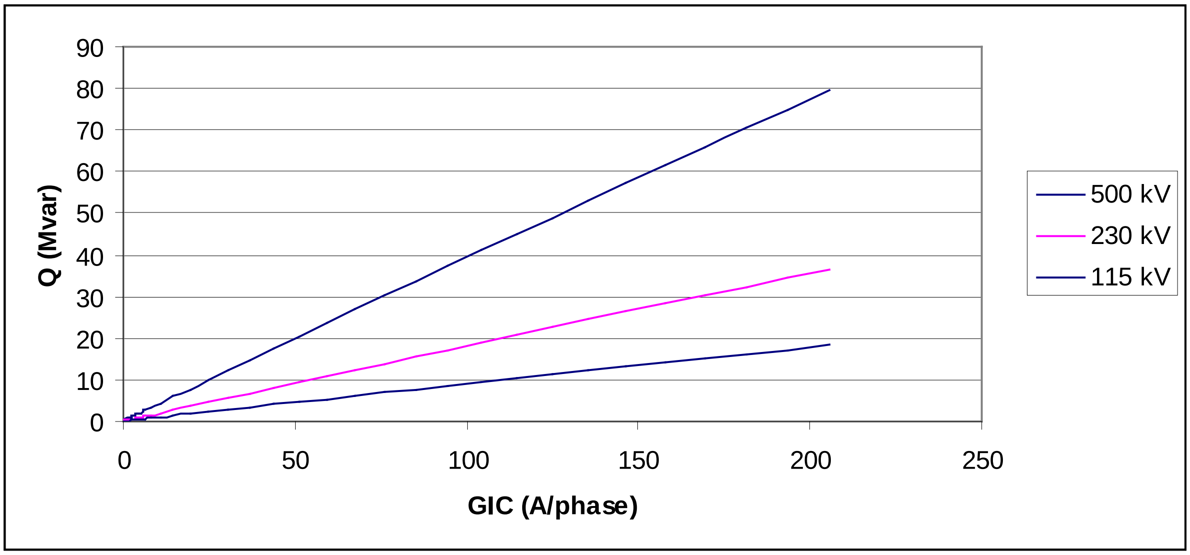

Figure 1: Reactive power absorption of a single-phase transformer vs. GIC

System Impact Considerations

A key element in a GMD event is the absorption of reactive power of high side wye-grounded transformers experiencing half-cycle saturation.

- In many jurisdictions bulk power transmission includes voltages > 200 kV. Tripping a transformer with high side voltage > 200 kV or reconfiguring > 200 kV circuits can impose serious constraints on operating limits; therefore, such operating scenarios must be considered in GMD impact studies.
- Generator step-up transformers are typically situated at electrical end points of the network where GIC tends to be highest. GSUs with high side voltages > 200 kV are not uncommon. On the other hand, GIC injected by circuits < 200 kV is limited because of the higher resistances of GSUs connected to < 200 kV networks
- Autotransformers are often used in networks above > 200 kV. The flow of GIC depends heavily on the relative resistances of various network elements and the geographical orientation of nearby transmission lines [14]. Considering a 500/230 kV autotransformer with one 500 kV and one 230 kV circuit, modelling GIC flow without taking into consideration the 230 kV circuit results in GIC overestimation between 20% and 30%. In a more complex configuration, the estimated GIC

ignoring the 230 kV circuits can over or underestimate GIC and the effects of GIC in transformers significantly. The appendix shows an example of this effect.

- From the point of view of GIC distribution in the network, transformer vulnerability is not a consideration. Including only transformers with high side windings > 300 kV would result in unrealistic GIC flow assessments (see Appendix)
- In systems where the bulk transmission voltages are 230 kV and 500 kV, neglecting circuits rated less than 300 kV would misrepresent GIC flows and var absorption, especially because GIC flow-through in 500 kV autotransformers would be neglected (see Appendix).

Appendix

This Appendix describes two examples where:

- The exclusion of 230 kV circuits at a station with 500/230 kV autotransformers cause significant errors in the estimation of GIC effects.
- The inclusion/exclusion of the 161 kV and 115 kV networks in a large utility within the Eastern Interconnect has minimal impact on the estimation of the effects of GIC in the system

Example 1: Exclusion of 230 kV circuits in a 500/230 kV transmission station

The distribution of GIC in a network, for a given geomagnetic latitude and earth structure, depends on a number of factors such as resistances of various circuit elements, induced voltages and network topology. There are times when a complex network topology can lead to non-intuitive results, such as the presence of a series capacitor causing an increase of GIC in a transformer.

To illustrate, consider the topology of the circuits connected to Transmission Station (TS) shown in Fig. A1. If a transmission circuit is sufficiently long it can be represented by a constant current source (since both induced voltage and line resistance are proportional to line length). In the case of a 500 kV circuit, GIC tends to be fairly constant for lengths > 150 km. A simplified representation is shown in Fig A2. The station has several autotransformers which have been lumped into a single equivalent autotransformer. The series capacitor bank is assumed to be out of service (bypassed).

Currents *I1* and *I2* represent the GIC contribution of the 500 kV circuits to the HV bus. Then,

$$I3 = I1 - I2 \qquad \text{(A.1)}$$

where *I3* is the total contribution of the 500 kV circuits to the series winding. The total contribution to the common winding is given by

$$Ig = I3 + I4 + I5 + I6 - I7 \qquad \text{(A.2)}$$

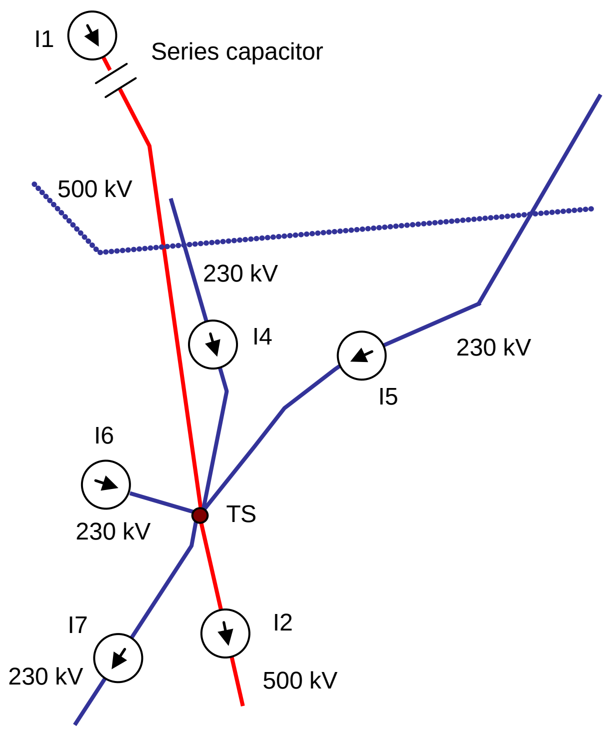

Fig. A1: HV transmission lines connecting to Essa TS.

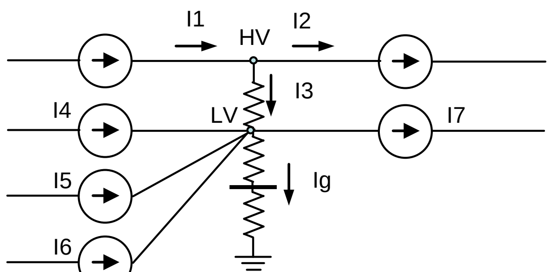

Fig. A2: Circuit representation of induced geoelectric fields and equivalent transformer representation.

Let us assume that the earth can be represented by a laterally-uniform earth model, and that the 500 kV circuits are in the same or similar orientation geographically with the same resistance per unit length, so that the injected GIC I1 and I2 are nearly identical (see Fig. A1). Then I3 will be small or zero and only the 230 kV circuits will contribute to the current in the transformer common winding Ig. If the 230 kV circuits were excluded, (i.e., I4 = I5 = I6 = I7 = 0) then I3 = Ig would be very small and the estimated effects of GIC on the autotransformer would be minimal.

If the 500 kV series capacitor bank in Fig. A1 is placed in service, then I1 = 0 and I2 = I3. The common-winding GIC is now equal to the sum of the GIC contributed by the 230 kV circuits and the remaining 500 kV circuit. Depending on the relative values of the contributions, the net GIC through the transformer may increase or decrease. Simulations show that in the network shown in Figure A1 when the series capacitors are in service, the effective GIC through the transformer increases by a factor of 30. This is not a general result, but rather a consequence of Kirchhoff's current law and a particular system topology.

If the series capacitor bank is in service and the 230 kV circuits are not taken into consideration all the GIC from the remaining 500 kV circuit would flow into the autotransformer and describe a completely different situation from in terms of the saturation of the autotransformer.

The cases described above were simulated with a GIC analysis tool and summarized in Table A1. Note that there are two 500/230 kV autotransformers in service in this simulation.

Table A1: Summary of the Effects of 230 kV Circuits in a Station with Two 500/230 kV Autotransformers

Geoelectric field 5 V/km	230 kV and 500 kV 500 kV Series caps in service	230 kV and 500 kV 500 kV Series caps bypassed	No 230 kV 500 kV Series caps in service	No 230 kV 500 kV Series caps bypassed
Transformer GIC/phase (A/phase)	99.9	2.8	127	5.5
I1 (A/phase)	0	365	0	338
I2 (A/phase)	146.8	334	254	349
Incremental metallic hot spot temperature (C°)	89	1.6	60	7.6
var absorption (Mvar)	128	14	151	12.5
THD (%)	17	2.5	18	2.2

The conclusion from this example is that it is not always possible to make generalizations in a network of relatively complex topology. While it is true that a series capacitor blocks GIC in the transmission line

where it is employed, it does not necessarily reduce GIC in system transformers. Furthermore, not taking into account the effects of the 230 kV circuits in this network would lead to inaccurate conclusions, such as a 33% underestimation of the hot spot temperature rise[1].

Example 2: Effects of the inclusion/exclusion of circuits below 200 kV

A portion of the Eastern Interconnect that contains 500 kV, 230 kV, 161 kV, and 115 kV facilities was modeled using PowerWorld software. When the GIC contribution of the 161 kV and 115 kV circuits was excluded, the effects on the network above 200 kV where found to be minimal. Table A2 summarizes the effects of including/excluding GIC contributions from the 161 kV and 115 kV network assuming a 5 V/km East-West geoelectric field. The differences in the results assuming a North-South geoelectric field are very similar, and are not reproduced in here.

Table A2: GIC Effects on the Network Above 200 kV Assuming an East-West 5 V/km Geoelectric Field

	Including 115 kV	Excluding 115 kV	Difference
Maximum transformer GIC (A/phase)	134.65	133.78	0.6 (%)
Average transformer GIC (A/phase)	13.79	13.46	2.4 (%)
Maximum transformer var absorption (Mvar)	150.3	149.5	0.7 (%)
Average transformer var absorption (Mvar)	7.16	7.08	1.1 (%)
Minimum bus voltage (pu)	0.98204	0.98548	0.4 (%)
Average bus voltage (pu)	1.01858	1.01897	0.04 (%)
Total system var loss due to GIC (Mvar)	3,935	3,801	3.4 (%)

These results are consistent with observations made in peer-reviewed technical publications such as [9].

[1] Hot spot heating was estimated using the methodology described in [15]

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Exhibit E

White Paper Supporting Functional Entity Applicability

Functional Entity Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators (RC) and Transmission Operators (TOP) with networks that contain power transformers with high side grounded wye windings above 200 kV. This applicability is consistent with the NERC Functional Model and existing standards where both entities are described as having responsibility and authority for reliable transmission operations within their scope. The drafting team determined that Balancing Authorities (BA) should not be among the applicable functional entities because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The drafting team also determined that Generator Operators (GOP) should not be among the applicable functional entities because any Operating Procedures to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment. Consistent with FERC Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03 and applicability of stage 2 standards will be considered separately.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779. While the applicability of the proposed stage 1 standard is limited to RCs and TOPs, other entities will be considered for stage 2 as outlined in the Standards Authorization Request.

Justification for Applicable Functional Entities

Reliability Coordinator

The RC has responsibility and authority for reliable operation within the Reliability Coordinator Area (RCA). The RC's scope includes a wide-area view with situational awareness of neighboring RCAs. The NERC Functional Model states:

> The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

The RC's authority is codified in IRO-001-1a which states:

> **R3.** The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
>
> **R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

Including the RC as an applicable entity in EOP-010-1 provides the necessary coordination for planning and real-time actions that is envisioned by the Functional Model and addresses Order No. 779 directives to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view.

Transmission Operator

Like the RC, the TOP has responsibility and authority for the reliable operation of the transmission system within a specified area. According to the NERC Functional Model:

> The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The TOP's authority is established in TOP-001-1a as follows:

> **R1.** Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.
>
> **R3**. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

The 2012 GMD Report contains web links for some TOP Operating Procedures to mitigate the effects of GMD events. Recently the GMD Task Force developed Operating Procedure templates that provide a technical resource for TOPs to use in developing procedures based on industry best practices. Included in the templates are actions that could be employed to mitigate the effects of GMD, such as reduction of equipment loading, increasing reactive reserves, reconfiguration of the system, recalling outages, and Load shedding. The templates also describe indicators of GMD conditions that could be used as trigger conditions for steps or tasks in an entity's Operating Procedures. Detailed study of system and equipment impacts can improve Operating Procedures. However, some procedures can be put in place without system studies to increase situational awareness and posture the system when a GMD event is forecasted.

Justification for Omitting Functional Entities

Balancing Authority

BAs are responsible for the Real-time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the TOP to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits.

The BA can be expected to address GMD impacts through use of generation. However, the BA would not initiate actions unilaterally during a GMD event and would instead respond to the direction of the TOP

and RC. As such, the independent actions that the BA would take are very limited, if any. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and the concurrence of the TOP and/or RC.

The RC and TOP will be preparing GMD Operating Plans, Operating Processes, and/or Operating Procedures to address steps that each will be taken to address GMD impacts. Some of those steps will require the BA to take action. As outlined above, the requirement for the BA to execute actions at the request of the TOP or RC is clear. Given that the BA would only take action at the request of the TOP or RC and that the required actions would be the same actions BAs take for other system events, the SDT concludes that the BA should not be included as an applicable entity in EOP-010-1.

Generator Operator

GOPs are the functional entity that operate generating unit(s) and perform the functions of supplying energy and reliability related services. They may be responsible for operating generator step up (GSU) transformers that connect the generator to the transmission system. Some GSU transformers are susceptible to geomagnetically-induced currents (GICs) during a GMD event, and operating actions are used by some GOPs to mitigate system or equipment impacts.

An effective GOP GMD Operating Procedure to mitigate the effects of GMD would require:

1. GSU transformer study to determine expected GIC on the GSU high side neutral level at their site (GIC/thermal rating study)
2. Ability to monitor GIC at the GSU high voltage wye-grounded winding neutral

Absent the above information, the GOP would not have the technical basis for taking steps on its own and would instead take steps based on the RC or TOP’s Operating Plans, Processes, or Procedures. Therefore, the SDT concludes that GOPs should be excluded as applicable entities in EOP-010-1.

Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure. Furthermore, the RC and TOP will be preparing GMD Operating Plans and Operating Processes or Procedures, respectively. Those will address steps that each will be taking to address GMD impacts, which may include requiring one or more GOPs to take action. Existing standards provide obligations for the GOP to execute actions when requested by the TOP or RC as described above.
Generator Owners (GOs) and GOPs are included in the Project 2013-03 Standards Authorization Request. They will be considered for inclusion in Stage 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. Such mitigation strategies could include the development of Operating Procedures for applicable GOs and GOPs.

Exhibit F

Analysis of Violation Risk Factors and Violation Security Levels

Violation Risk Factor and Violation Severity Level Justifications

EOP-010-1 – Geomagnetic Disturbance Operations

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-010-1 – Geomagnetic Disturbance Operations.

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

The Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk

Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

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

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

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

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

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

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

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

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

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justifications – EOP-010-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to implement a GMD Operating Plan when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, failure to implement a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. Failure to develop or maintain a GMD Operating Plan could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, failure to develop or maintain a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the importance of having coordinated GMD Operating Procedures and the RC's role in the planning and operations time horizons.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned. The requirement uses Parts to identify the items to be included in a GMD Operating Plan. The VRF for this requirement is consistent with Requirement R3 with regard to relative risk.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with IRO 014-1 Requirement R1, which requires the Reliability Coordinator to have Operating Procedures, Processes, or Plans in place to support interconnection reliability. The drafting team believes the reliability objective of IR0-014-1 Requirement R1 is most comparable to the proposed Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A Violation Risk Factor of Medium is consistent with NERC VRF definition. Failure to implement a GMD Operating Plan when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, failure to implement a GMD Operating Plan is unlikely to lead to BES instability, separation,

VRF Justifications – EOP-010-1, R1	
	or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. Failure to develop or maintain a GMD Operating Plan could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, failure to develop or maintain a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the significance of the RC's role in coordinating GMD Operating Procedures in the planning and operations time horizons.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The assigned risk level reflects the most important objective of the requirement.

Proposed VSLs – EOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area

VSL Justifications – EOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent	The proposed VSL is worded consistently with the corresponding requirement.

with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justifications – EOP-010-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to disseminate forecasted and current space weather information could directly and adversely affect the electrical state or capability of the Bulk Electric System during a GMD event. However, failure to disseminate forecasted and current space weather information is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. This requirement and VRF reflects the drafting team's view of the significance of consistent space weather information for coordination of GMD Operating Procedures in each Reliability Coordinator Area and maintains responsibility for providing this information on the Reliability Coordinator as established in IRO-005-3.1a.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements and a single VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with IRO-008-1 Requirement R3 which requires the Reliability Coordinator to share information with specific entities that are expected to take operational actions when a potential Interconnection

VRF Justifications – EOP-010-1, R2	
	Reliability Operating Limit violation is anticipated. Dissemination of space weather forecast information can be considered a similar information sharing activity with an impact that would not exceed IRO-008-1 Requirement R3.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. Failure to disseminate forecasted and current space weather information could directly and adversely affect the electrical state or capability of the Bulk Electric System during a GMD event. However, failure to disseminate forecasted and current space weather information is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. This requirement and VRF reflects the drafting team's view of the significance of consistent space weather information for coordination of GMD Operating Procedures in each Reliability Coordinator Area and maintains responsibility for providing this information on the Reliability Coordinator as established in IRO-005-3.1a.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – EOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.

VSL Justifications – EOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The drafting team believes that a single VSL is most appropriate for describing noncompliant performance of the requirement. Dissemination of space weather information will most likely be accomplished using automated communication systems such as all-call or electronic distribution lists. As a result the RC's compliance will be evaluated on a binary basis for implementing a notification system to disseminate space weather information.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL. IRO-005-3.1a requirement R3 provided a similar compliance obligation without a FERC-approved VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL assignment category for a binary requirement is consistent. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications – EOP-010-1, R2	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on number of violations.

VRF Justifications – EOP-010-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to implement a GMD Operating Procedure or Operating Process when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, this failure is unlikely to lead to BES instability, separation, or cascading failures. The Transmission Operator and other applicable entities are responsible for maintaining the reliability of the BES under within their respective areas in all circumstances. Failure to develop or maintain a GMD Operating Procedure or Operating Process could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, this failure is unlikely to lead to BES instability,

VRF Justifications – EOP-010-1, R3	
	separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the importance of developing and maintaining coordinated and predetermined operating procedures or processes in the planning horizon, and for implementing the operating procedures or processes when conditions warrant in the operations time horizon.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned. The requirement uses Parts to identify the items to be included in a GMD Operating Procedure or Operating Process. The VRF for this requirement is consistent with Requirement R1 with regard to relative risk.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with EOP 001-2.1b, requirement R2.2 which requires the Transmission Operator to develop, maintain, and implement plans to mitigate operating emergencies on the transmission system. Additionally, it is consistent with IRO 014-1 Requirement R1, which requires the Reliability Coordinator to have Operating Procedures, Processes, or Plans in place to support interconnection reliability. Although the functional entities are different, the reliability objective of IR0-014-1 Requirement R1 is comparable to the proposed Requirement R3.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. Failure to implement a GMD Operating Procedure or Operating Process when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, this failure is unlikely to lead to BES instability, separation, or cascading failures. The Transmission Operator and other applicable entities are responsible for maintaining the reliability of the BES under within their respective areas in all circumstances. Failure to develop or maintain a GMD Operating Procedure or Operating Process could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, this failure is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the

VRF Justifications – EOP-010-1, R3	
	importance of developing and maintaining coordinated and predetermined operating procedures or processes in the planning horizon, and for implementing the operating procedures or processes when conditions warrant in the operations time horizon.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The assigned risk level reflects the most important objective of the requirement.

Proposed VSLs – EOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator had a GMD Operating Procedure or Operating Process, but failed to maintain it.	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	The Transmission Operator did not have a GMD Operating Procedure or Operating Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

VSL Justifications – EOP-010-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of	There is no prior compliance obligation related to the subject of this standard.

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

Exhibit G

Analysis of Commission Directives

Order No. 779 Citation	Directive/Guidance	Resolution in EOP-010-1
P 36	The Commission directs NERC to submit, within six months of the effective date of this Final Rule, one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System.	Requirement R1 requires Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. Requirement R3 requires Transmission Operators to develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. Analysis of the applicable functional entities is provided in a white paper posted on the project page. (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx)
P 38	The Commission is not directing NERC to develop Reliability Standards that include specific operational procedures. Instead, as proposed in the NOPR, the Reliability Standards should include a mechanism that requires responsible entities to develop and implement operational procedures because owners and operators of the Bulk-Power System are most familiar with their own equipment and system configurations. In addition, we do not expect that owners and operators of the Bulk-Power System will necessarily develop and implement the same operational procedures. Instead, the Reliability Standards, rather than include "one-size-fits-all" Requirements, should allow responsible entities to tailor their operational procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology, identified in the Reliability Standards. In addition, as we stated in the NOPR, the coordination of operational procedures across regions is an important issue that should be considered in the NERC standards development process.[68] The coordination	EOP-010-1 is not prescriptive and allows entities to tailor their Operational Procedures or Operating Processes based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology. Requirement R1 addresses coordination and requires Reliability Coordinators to develop, maintain and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. The coordination of Operating Procedures and

Order No. 779 Citation	Directive/Guidance	Resolution in EOP-010-1
	of operational procedures across regions and data sharing might be overseen by planning coordinators or another functional entity with a wide-area perspective.[69] The NERC standards development process, as stated in the NOPR, should also consider operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for damaged equipment that could be de-rated or out-of-service for an extended period of time.	Operating Processes across regions is addressed through existing Reliability Standards. EOP-005 (System Restoration from Blackstart Resources) and EOP-006 (System Restoration Coordination) address Bulk-Power System restoration following a Disturbance. These plans are expected to be effective for restoration following any unplanned event. A duplicative requirement was not included in EOP-010-1.

Exhibit H

Summary of Development History and Complete Record of Development

Exhibit H—Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard EOP-010-1

The development record for proposed Reliability Standard EOP-010-1 is summarized below.

I. Overview of the Standard Drafting Team

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

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted on June 12, 2013 and approved by the Standards Committee ("SC") on June 21, 2013.

B. First Posting – Formal Comment Period and Ballot

Proposed Reliability Standard EOP-010-1 was posted for a 45-day formal public comment period and ballot from June 27, 2013 through August 12, 2013. There were 85 sets of responses, including comments from approximately 225 individuals from approximately 140 companies representing all 10 industry segments. Proposed Reliability Standard EOP-010-1 received a quorum of 76.32% and an approval 62.74%.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard EOP-010-1 based on those comments:

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

- A new Requirement R2 was added to the proposed Reliability Standard, which would require the Reliability Coordinator ("RC") to disseminate space weather forecast information to Transmission Operators (TOP) in their Reliability Coordinator Area. IRO-005-3.1a Requirement R3 provided for that obligation, however, the NERC Board approved IRO-005-4 which resulted in retirement of the requirement. The new Requirement R2 in EOP-010-1 will maintain the RC's responsibility for providing space weather forecast information. The implementation plan includes guidance for making the new Requirement R2 effective to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010-1 Requirement R2 are effective at the same time.
- In response to stakeholder comments that certain Requirements met Paragraph 81 criteria, administrative requirements for reviewing of GMD Operating Plans and Procedures within a 36-month period and for having a copy in the control room were removed.
- Balancing Authorities ("BA") have been removed from the applicable functional entities because there are no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The BA is not expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the TOP and RC. Existing Reliability Standards provide the required authority for action. A whitepaper with the standard drafting team's analysis was posted on the project page.
- The applicable TOP was been clarified to include only those that operate power transformers with a high side wye-grounded winding with terminal voltage greater than 200 kV. This applicability statement describes the functional entity in terms of the assets that they operate, which could include non-BES assets. The applicability statement is not intended to define equipment to be protected by the Operating Procedures. The standard drafting team views 200 kV as the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. A whitepaper with the drafting team's analysis was posted on the project page.
- Although some stakeholders suggested that Generator Operators (GOP) be added to the proposed Reliability Standard as applicable entities, the standard drafting team maintained that GOP Operating Procedures designed to mitigate the effects of GMD would need to be supported by an equipment-specific study and might require the use of GMD monitoring equipment. Because it is not reasonable to assume that all GOP have such studies or monitoring equipment, GOP have not been added to proposed Reliability Standard EOP-010-1. Consistent with Commission Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03, and Generator Owners (GO) and GOP will be considered for applicability with Stage 2. A whitepaper with the standard drafting team's analysis supporting the applicability of proposed Reliability Standard EOP-010-1 was posted on the project page.
- Some stakeholders also commented that the six-month implementation period was too short. The drafting team was sympathetic to the challenge of completing the necessary coordination in a six-month time period. However, this implementation period was suggested in Order No. 779 and the standard drafting team lacks strong justification for a specific longer period.
- Several changes in language were made to improve the clarity of requirements and measures.

C. Second Posting – Formal Comment Period and Additional Ballot

Proposed Reliability Standard EOP-010-1 was posted for a 45-day formal public comment period from September 4, 2013 through October 21, 2013. There were 37 sets of responses, including comments from approximately 120 individuals from approximately 80 companies representing 9 of the 10 industry segments. Proposed Reliability Standard EOP-010-1 received a quorum of 77.58% and an approval 88.75%.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard EOP-010-1 based on those comments:

- In Section 5 (Background), capitalized "Protection System" because it is defined in the NERC Glossary of Terms.
- In Requirement R1, revised the Requirement to include the term "Operating Process" in R1 and R1 part 1.2 and changed language to be consistent with Requirement R3. The revised Requirement with highlighted changes is as follows:
  - **R1**. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*
    - **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.
    - **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within ~~the~~ its Reliability Coordinator Area.
- In Measure M1, inserted the word "current" to align with NERC guidelines for writing Measures to support this type of Requirement. The revised Measure with the highlighted change is as follows:
  - **M1**. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.
- In Requirement R2, clarified that the Reliability Coordinator shall disseminate forecasted and current space weather information *to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan*. The revised requirement with highlighted change is as follows:
  - **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients ~~as specified~~ in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*
- In Requirement R3, inserted "GMD", so that the phrase "GMD Operating Procedure or Operating Process" would be consistent with Requirement R1. The revised Requirement is as follows:
  - **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating

Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

- A clarifying change was made to the Implementation Plan to conform to the effective date language in the proposed Reliability Standard, which was changed in the prior draft in response to concerns raised by Canadian entities.

D. Final Ballot

Proposed Reliability Standard EOP-010-1 was posted for a 10-day final ballot period on October 25, 2013 through November 4, 2013. The proposed Reliability Standard received a quorum of 86.90% and an approval rating of 91.95%.

E. Board of Trustees Approval

Proposed Reliability Standard EOP-010-1 was approved by the NERC Board of Trustees on November 7, 2013.

Related Files

Status:
EOP-010-1 was approved by industry and will proceed to the NERC Board of Trustees for adoption at its November 2013 meeting.

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

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

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

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

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

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

Draft	Action	Dates	Results	Consideration of Comments
Draft 3 **Stage 1 Standard** EOP-010-1 Clean | Redline to last posting Implementation Plan Clean | Redline to last posting **Supporting Materials:** Standard Authorization Request White Paper Supporting Network Applicability of EOP-010-1 Clean |Redline to last posting White Paper Supporting Functioning Entity Applicability of EOP-010-1 Clean |Redline to last posting	Final Ballot Info>> Vote>>	10/25/13 - 11/04/13 (closed)	Summary>> Ballot Results>>	

GMD Task Force Operating Procedures Waiver Authorized by SC but not Exercised Violation Risk Factor and Violation Severity Level Justifications Stage 1 Directives Map				
Draft 2 **Stage 1 Standard** **EOP-010-1** Clean | Redline to last posting **Implementation Plan** Clean | Redline to last posting **Supporting Materials:** Unofficial Comment Form (Word) Standard Authorization Request White Paper Supporting Network Applicability of EOP-010-1 White Paper Supporting Functional Entity Applicability of EOP-010-1 GMD Task Force Operating Procedures	Comment Period Info>> Submit Comments>>	09/04/13 - 10/21/13 (closed)	Summary>> Ballot Results>> Non-binding Poll Results>> Comments Received>>	Consideration of Comments>>
	Additional Ballot and Non-Binding Poll Updated Info>> Info>> Vote>>	10/09/13 - 10/21/03 Extended an additional day to achieve quorum. (closed)		
Draft Stage 1 Standard EOP-010-1 Implementation Plan Standard Authorization Request **Supporting Materials:** Unoffical Comment Form (Word) GMD Task Force Operating Procedures	Comment Period Info>> Submit Comments>>	06/27/13 - 08/13/13 (closed)	Summary>> Ballot Results>> Non-binding Poll Results>> Comments Received>>	Consideration of Comments>>
	Ballot and Non-binding Poll Info>> Vote>>	08/02/13 - 08/13/13 (closed)		
	Join Ballot Pool>>	06/27/13 - 07/26/13 (closed)		

Draft 1

Stage 1 Standard

Standard Development Timeline

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

Development Steps Completed

Description of Current Draft

This draft is the first posting of the proposed standard and is being done in conjunction with the posting of the SAR for this project.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	June 2013
45-day Formal Comment Period with Parallel Initial Ballot	August 2013
Successive Ballot (if needed)	September 2013
Recirculation ballot	November 2013
BOT adoption	November 2013

Effective Dates

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03	N/A

Definitions of Terms Used in Standard

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

None

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**

2. **Number:** EOP-010-1

3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV

   4.1.3 Transmission Operator with a Transmission Operator Area that includes any transformer with high side terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to negatively impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and protection system Misoperation, the combination of which can lead to voltage collapse and blackout.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan to coordinate GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities in the Reliability Coordinator Area are coordinated and compatible.

M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented such as correspondence with Transmission Operators and Balancing Authorities.

R2. Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has reviewed its GMD Operating Plan within the timeframe of Requirement R2 such as a dated review signature sheet or revision history.

R3. Each Transmission Operator and Balancing Authority shall develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedures shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

3.1. The steps or tasks for the acquisition and dissemination of space weather information to its System Operators.

3.2. The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan to mitigate the effects on the system from GMD events.

3.3 The predetermined trigger conditions for initiating and terminating steps or tasks in the Operating Procedure.

M3. Each Transmission Operator and Balancing Authority shall have GMD Operating Procedures meeting all the provisions of Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M4. Each Transmission Operator and Balancing Authority shall have evidence that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4 such as a dated review signature sheet or revision history.

R5. Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Transmission Operator and Balancing Authority shall have hard copies or electronic copies of its GMD Operating Procedure available for inspection as stated.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for 3 years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning	Medium	The Reliability Coordinator failed to maintain a GMD Operating Plan	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the elements listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area
R2	Long-term Planning, Operations Planning	Medium	The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than 39 months, since the effective date.	The Reliability Coordinator reviewed its GMD Operating Plan more than 39 months, but less than 42 months, since the effective date.	The Reliability Coordinator reviewed its GMD Operating Plan more than 42 months since the effective date.	The Reliability Coordinator did not review its GMD Operating Plan
R3	Long-term Planning, Operations Planning	Medium	The responsible entity failed to maintain GMD Operating Procedures	The responsible entity's GMD Operating Procedures failed to include one element in Requirement R3, parts	The responsible entity's GMD Operating Procedures failed to include two or more elements in Requirement R3, parts	The responsible entity did not have GMD Operating Procedures OR The responsible entity

				3.1 through 3.3.	3.1 through 3.3.	failed to implement its GMD Operating Procedures.
R4	Long-term Planning, Operations Planning	Medium	The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective date.	The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 39 months, but less than 42 months, since the last effective date.	The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 42 months since the last effective date.	The responsible entity did not review its GMD Operating Procedures and submit them for approval.
R5	Long-term Planning, Operations Planning	Medium	N/A	N/A	N/A	The responsible entity did not have copies of its GMD Operating Procedures in its primary control room and all backup control rooms if applicable.

D. Regional Variances

None.

E. Interpretations

None.

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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator
Balancing Authority with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV
Transmission Operator with a Transmission Operator Area that includes any transformer with a high side terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

EOP-010-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, six calendar months following applicable regulatory approval.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, six calendar months following Board of Trustees approval.

Standards Authorization Request Form

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

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

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

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

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

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

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

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

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

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

Related SARs	
SAR ID	Explanation

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

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Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft stage 1 EOP-010-1 Standard. The electronic comment form must be completed by 8:00 p.m. ET by Monday, **August 12, 2013**.

If you have questions please contact Mark Olson via email or by telephone at 404-446-9760.

The project page may be accessed by clicking here.

Background Information

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order No. 779.

This posting is soliciting comment on a draft stage 1 Standard and a Standard Authorization Request (SAR) addressing stages 1 and 2. The draft Standard is a new EOP Standard to specifically address the stage 1 directives in Order No. 779. Including GMD requirements in an existing EOP Standard is not feasible within the prescribed filing deadline due to the other relevant directives and 5-year review requirements that must be considered by the drafting team to revise the existing Standards. This effort to revise older EOP Standards is being carried out by a 5-year review team.

Question 1 asks for stakeholder comment on applicability of the stage 1 Standards. The draft stage 1 Standard applies to Reliability Coordinators, Balancing Authorities with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV, and Transmission Operators with a Transmission Operator Area that includes any transformer with high side terminal voltage greater than 200 kV. While some Generator Operators also have Operating Procedures to mitigate the effects of GMD, the standards drafting team (SDT) did not support including them in mandatory stage 1 standards because the actions that would be included in a Generator Operator's procedures would require studies and monitoring equipment that will not be addressed until stage 2. Applicability was also limited by the minimum voltage threshold of 200 kV. Experience with modeling geomagnetically-induced currents (GIC) has shown that because the resistances of conductors are much higher in systems below 200 kV, the affects of GMD on these systems are significantly reduced. Historical evidence of transmission systems affected by severe solar storms supports this conclusion. The 2012 GMD Report contains additional information.

Question 2 asks for stakeholder comment on Requirement R1, which requires Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan. This coordinating role for the RC is based on the functional model and addresses Order No. 779 directives to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view. The defined term "Operating Plan" provides the RC with latitude to determine specific activities necessary to achieve this goal.

Question 3 asks for stakeholder comment on Requirement R3, which requires Transmission Operators and Balancing Authorities to develop, maintain, and implement GMD Operating Procedures. The draft standard is intended to allow entities to develop their own procedures based on entity-specific factors. Recently the GMD Task Force developed Operating Procedure templates that provide a technical resource for entities to use in developing procedures. Included in the templates are a number of actions that could be employed to mitigate the effects of GMD, such as reduction of equipment loading, increasing reactive reserves, reconfiguration of the system, recalling outages, and Load shedding. The templates also describe indicators of GMD conditions that could be used as trigger conditions for steps or tasks in an entity's Operating Procedures.

Question 4 asks for stakeholder comment on Requirements R2, R4, and R5. R2 and R4 require applicable entities to review their GMD Plans/Operating Procedures every 36-months. This periodicity would ensure improvements in the scientific understanding of GMDs can be incorporated into Operating Procedures in a timely manner as directed in Order No. 779. Requirement R5 requires each Transmission Operator and Balancing Authority to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms, which is consistent with other EOP Reliability Standards.

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

Questions (1-5) on Draft 1 of EOP-010-1

1. The SDT is proposing that the draft stage 1 Standard should apply to Reliability Coordinators, Balancing Authorities with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV, and Transmission Operator with a Transmission Operator Area that includes any transformer with high side terminal voltage greater than 200 kV. Do you agree that the SDT has correctly identified the applicable functional entities in the initial draft stage 1 Standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

2. In Requirement R1, the SDT is proposing to require Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan. This coordinating role for the RC is based on the functional model and addresses the Order No. 779 directive to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view. The defined term "Operating Plan" provides the RC with latitude to determine specific activities necessary to achieve this goal. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

3. In Requirement R3, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to develop, maintain, and implement GMD Operating Procedures. The draft Standard is intended to allow each entity to develop its own procedures based on entity-specific factors as directed in Order No. 779. Do you agree that the SDT has correctly addressed the stage 1 directives in Order No. 779? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

4. In Requirements R2 and R4 the SDT is proposing to require applicable entities to review their GMD Plans/Operating Procedures every 36-months. This periodicity would ensure improvements in the scientific understanding of GMDs can be incorporated into Operating Procedures in a timely manner as directed in Order No. 779. In Requirement R5, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms, which is consistent with other EOP reliability standards. Do you agree that the SDT has correctly addressed the directives in Order No. 779 in a manner that is good for reliability with these requirements? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

5. If you have any other comments on this draft Standard that you haven’t already mentioned above, please provide them here:

Comments:

Questions (6-10) on SAR for Project 2013-03

The scope of this project is intended to address FERC directives from Order No. 779, including:

- Within six months of the effective date of Final Rule, NERC submit for approval one or more Reliability Standards that require owners and operators to develop and implement operational procedures to mitigate the effects of GMDs.
- Within 18-months of the effective date of Final Rule, NERC submit one or more Reliability Standards that require owners and operators to conduct initial and on-going assessments of the potential impact of benchmark GMD events.
- The Second Stage GMD Reliability Standard must identify what severity GMD events (i.e., benchmark GMD events) that responsible entities will have to assess for potential impacts.
- If the assessments identify potential impacts from benchmark GMD events, owners and operators must develop and implement a plan to protect against instability, uncontrolled separation, and Cascading.
- The standards development process should consider tasking Planning Coordinators, or another functional entity with a wide-area perspective, to coordinate mitigation plans across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness.
- The Second Stage GMD Reliability Standards should not impose “strict liability” on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity.

6. Do you agree that the SAR, as drafted, provides a scope within which to address the directives in Order No. 779? If not, please explain.

☐ Yes
☐ No
Comments:

7. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

☐ Yes
☐ No
Comments:

8. The intent of the project is to develop continent-wide requirements that allow responsible entities to tailor operational procedures or strategies based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology. However, the need for regional variances will be researched throughout the proposed project and may be supported by analysis required to develop stage 2 Standard(s). Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance in your comments:

☐ Yes
☐ No
Comments:

9. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice in your comments:

☐ Yes
☐ No
Comments:

10. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.

Comments:

Geomagnetic Disturbance Operating Procedure Template

Transmission Operator

Overview

Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of geomagnetically induced currents (GIC) on system reliability. They also have the merit of being relatively easy to change as new information and understanding concerning this threat becomes available. Operating procedures need to be easily understood by, and provide clear direction to, operating personnel. This is especially true since most operators are unlikely to frequently respond to significant GMD events.

Some actions listed below should only be undertaken if supported by an adequate GIC impact study and/or if adequate monitoring systems are available. Otherwise they can make matters worse. Those actions are indicated by the phrase "if supported by studies".

Determining that a geomagnetic disturbance (GMD) is significant enough to warrant the initiation of special operating procedure(s) depends on the geographical location of the power system/equipment in question coincident with the location of the GMD measurement and forecast. Amount of advance notice obviously factor heavily in what specific actions can and should be taken. Note these are recommended actions; specific actions may vary by system configuration, system design and geographic location of the entity.

Information and Indications

The following are triggers that could be used to initiate operator action:

- External:
  - NOAA Space Weather Prediction Center or other organization issues:
    - Geomagnetic storm Watch (1-3 day lead time)
    - Geomagnetic storm Warning (as early as 15-60 minutes before a storm, and updated as solar storm characteristics change)
    - Geomagnetic storm Alert (current geomagnetic conditions updated as k-index thresholds are crossed)
- Internal:
  - System-wide:
    - Reactive power reserves
    - System voltage/MVAR swings/current harmonics
  - Equipment-level:

- GIC measuring devices
- Abnormal temperature rise (hot-spot) and/or sudden significant gassing (where on-line DGA available) in transformers
- System or equipment relay action (e.g., capacitor bank tripping)

Actions Available to the Operator

The following are possible actions for Transmission Operators based on available lead-time:

Long lead-time (1-3 days in advance, storm possible)

1. Increase situational awareness
   a. Assess readiness of black start generators and cranking paths
   b. Notify field personnel as necessary of the potential need to report to individual substations for on-site monitoring (if not available via SCADA/EMS)
2. Safe system posturing (only if supported by study; allows equipment such as transformers and SVCs to tolerate increase reactive/harmonic loading; reduces transformer operating temperature, allowing additional temperature rise from core saturation; prepares for contingency of possible loss of transmission capacity)
   a. Return outaged equipment to service (especially series capacitors where installed)
   b. Delay planned outages
   c. Remove shunt reactors
   d. Modify protective relay settings based on predetermined harmonic data corresponding to different levels of GIC (provided by transformer manufacturer).

Day-of-event (hours in advance, storm imminent):

1. Increase situational awareness
   a. Monitor reactive reserve
   b. Monitor for unusual voltage, MVAR swings, and/or current harmonics
   c. Monitor for abnormal temperature rise/noise/dissolved gas in transformers[1]
   d. Monitor geomagnetically induced current (GIC[2]) on banks so-equipped[3]
   e. Monitor MVAR loss of all EHV transformers as possible

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[1] Requires proper instrumentation (e.g., fiber to hot-spot). Note there may be unusual heating in a location other than the normal hot-spot location. Dissolved gas analysis may be available in real-time if the transformer is so-equipped; otherwise, post-event DGA may be performed.
[2] 10 amperes per phase GIC is a good starting point for potential impacts on heavily loaded transformers when actual limits are unknown. Newer transformers may have significantly higher GIC withstand capability if specified at the time of construction. For vulnerable transformers, the OEM can perform analytical withstand studies to better define a particular design's GIC vs. Time withstand capability
[3] Regarding the effects of GIC on transformers, real-time mitigation (after a storm is already in progress) should not be taken based solely on a single indicator (e.g., increased GIC). At least one additional indicator should be monitored to determine if the transformer is actually being adversely affected (e.g., increased MVAR loss, abnormal temperature rise, etc)

f. Prepare for unplanned capacitor bank/SVC/HVDC tripping[4]
g. Prepare for possible false SCADA/EMS indications if telecommunications systems are disrupted (e.g., over microwave paths)

2. Safe system posturing (only if supported by study)
   a. Start off-line generation, synchronous condensers
   b. Enter conservative operations with possible reduced transfer limits
   c. Ensure series capacitors are in-service (where installed)

Real-time actions (based on results of day-of-event monitoring):

1. Safe system posturing (only if supported by study)
   a. Selective load shedding[5]
   b. Manually start fans/pumps on selected transformers to increase thermal margin (check that oil temperature is above 50° C as forced oil flow at lower temperatures may cause static electrification)
2. System reconfiguration (only if supported by study)
   a. Remove transformer(s) from service if imminent damage due to overheating (possibly automatic by relaying)
   b. Remove transmission line(s) from service (especially lines most influenced by GMD)

Return to normal operation

This should occur two to four hours after the last observed geomagnetic activity.

Related Documents and Links

2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbance on the Bulk Power System, dated February 2012
http://www.nerc.com/files/2012GMD.pdf

Industry Advisory: Preparing for Geomagnetic Disturbances, dated May 10, 2011
http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf

4 Consideration should be given to replacing protective relaying (as part of planned GIC mitigation projects) to prevent false tripping of reactive assets due to GIC should be considered. Note that capacitor units have harmonic overload limits that should be observed (see IEEE Std 18).

5 Giving preference of course to the most critical/sensitive loads (e.g., national security, nuclear fuel storage site, nuclear plant offsite sources, chemical plants, emergency response centers, hospitals, etc)

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

Formal Comment Period: June 27, 2013 – August 12, 2013
Ballot Pools Forming Now: June 27, 2013 – July 26, 2013

Upcoming:
Ballot and Non-Binding Poll: August 2-12, 2013

Now Available

A 45-day formal comment period for **EOP-010-1 - Geomagnetic Disturbance Operations** is open through **8 p.m. Eastern on Monday, August 12, 2013**. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Friday, July 26, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

The EOP-010-1 (Geomagnetic Disturbance Operations) initial draft standard, implementation plan, and VRFs/VSLs are being developed to meet the directives of FERC Order No. 779 for stage 1 (Operating Procedures) Standards. In the Order FERC established a January 2014 filing deadline for Stage 1 standards. Stakeholders are encouraged to review the posted material early and provide comments and recommendations for substantive issues that must be addressed to gain their support, as opportunities to revise and ballot the standard are limited.

Under the revised Standard Processes Manual approved by FERC on June 26, 2013, the EOP-010-1 initial draft standard and associated implementation plan, VRFs and VSLs are posted for a 45-day comment period, with ballot pool formation during the first 30 days, a ballot and non-binding poll during the last 10 days of the 45-day period. The SAR for this project is also posted for comment.

Background information for this project, including a link to the Operating Procedure templates developed by the GMD Task Force, can be found on the project page.

Instructions for Joining Ballot Pool

Ballots pools are being formed for EOP-010-1 (Geomagnetic Disturbance Operations) and the associated non-binding polls in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submittal of an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Initial Ballot: bp-2013-03_GMD_in@nerc.com
Non-Binding poll: bp-2013-03_GMD_1_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, August 12, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

A ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

Ballot and Non-Binding Poll Results

Now Available

A ballot for **EOP-010-1 - Geomagnetic Disturbance Operations** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Tuesday, August 13, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 76.32%	Quorum: 75.89%
Approval: 62.74%	Supportive Opinions: 55.45%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. The standard will then proceed to an additional comment period and ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2013-03 GMD Initial Ballot
Ballot Period:	8/2/2013 - 8/13/2013
Ballot Type:	Initial
Total # Votes:	303
Total Ballot Pool:	397
Quorum:	**76.32 % The Quorum has been reached**
Weighted Segment Vote:	62.74 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	37	0.474	41	0.526	0	3	24
2 - Segment 2	10	0.5	5	0.5	0	0	0	0	5
3 - Segment 3	91	1	43	0.614	27	0.386	0	2	19
4 - Segment 4	30	1	11	0.524	10	0.476	0	1	8
5 - Segment 5	89	1	28	0.467	32	0.533	0	11	18
6 - Segment 6	54	1	19	0.487	20	0.513	0	0	15
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	6	0.3	3	0.3	0	0	0	0	3
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**397**	**6.8**	**155**	**4.266**	**131**	**2.534**	**0**	**17**	**94**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	COMMENT RECEIVED
1	American Electric Power	Paul B Johnson	Negative	COMMENT RECEIVED
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	COMMENT RECEIVED
1	Avista Utilities	Heather Rosentrater	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Balancing Authority of Northern California	Kevin Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see SMUD's Comment)
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish County Public Utility District)
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool, Inc)
1	Colorado Springs Utilities	Paul Morland	Negative	COMMENT RECEIVED
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Negative	COMMENT RECEIVED
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	

1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Spring Utilities)
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP MRO-NSRF)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ed Mackowicz)
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's NSRF)
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Power and Light)
				SUPPORTS

1	Portland General Electric Co.	John T Walker	Negative	THIRD PARTY COMMENTS - WECC(WECC Position Paper) - (WECC Position Paper)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	COMMENT RECEIVED
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	COMMENT RECEIVED
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	COMMENT RECEIVED
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell		
1	Transmission Agency of Northern California	Bryan Griess	Negative	COMMENT RECEIVED
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	

2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren Services)
3	American Public Power Association	Nathan Mitchell		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Farmington	Linda R Jacobson	Negative	COMMENT RECEIVED
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool, Inc)
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Negative	COMMENT RECEIVED
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		

3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Negative	SUPPORTS THIRD PARTY COMMENTS - (D. Jacoby)
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Spring Utilities)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	SUPPORTS THIRD PARTY COMMENTS - (U.S. Bureau of Reclamation and Western Area Power Administration)
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments and MRO NSRF comments.)
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ed Mackowicz)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD - Joe Tarantino) - (LPPC)
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Negative	COMMENT RECEIVED
3	PNM Resources	Michael Mertz	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC Staff comments)
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	

3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	COMMENT RECEIVED
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	COMMENT RECEIVED
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney)
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen		
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dave Szulczewski)
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, Florida Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Old Dominion Electric Coop.	Mark Ringhausen		

4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren Services)
5	Arizona Public Service Co.	Scott Takinen	Negative	COMMENT RECEIVED
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool, Inc)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
				SUPPORTS

5	Detroit Edison Company	Alexander Eizans	Negative	THIRD PARTY COMMENTS - (Kathleen Black)
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pablo Onate)
5	Electric Power Supply Association	John R Cashin		
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	SUPPORTS THIRD PARTY COMMENTS - (LDWP)
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	MidAmerican Energy Co.	Neil D Hammer	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP and MRO)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	COMMENT RECEIVED
5	Oglethorpe Power Corporation	Bernard Johnson		

5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT RECEIVED
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	COMMENT RECEIVED
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	COMMENT RECEIVED
6	City of Redding	Marvin Briggs		
				SUPPORTS

6	Cleco Power LLC	Robert Hirchak	Negative	THIRD PARTY COMMENTS - (Southwest Power Pool, Inc)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pablo Onate)
6	FirstEnergy Solutions	Kevin Querry		
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Negative	SUPPORTS THIRD PARTY COMMENTS - (LADWP Regulatory Group)
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Negative	SUPPORTS THIRD PARTY COMMENTS - (U.S. Bureau of Reclamation and Western Area Power Administration)
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ryan Millard)
6	Platte River Power Authority	Carol Ballantine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Light & Power)
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	COMMENT RECEIVED

6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	COMMENT RECEIVED
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		Debra R Warner		
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Michigan Public Service Commission	Donald J Mazuchowski		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	COMMENT RECEIVED

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation EOP-010-1

Formal Comment Period: June 27, 2013 – August 12, 2013
Ballot Pools Forming Now: June 27, 2013 – July 26, 2013

Upcoming:
Ballot and Non-Binding Poll: August 2-12, 2013

Now Available

A 45-day formal comment period for **EOP-010-1 - Geomagnetic Disturbance Operations** is open through **8 p.m. Eastern on Monday, August 12, 2013**. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Friday, July 26, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

The EOP-010-1 (Geomagnetic Disturbance Operations) initial draft standard, implementation plan, and VRFs/VSLs are being developed to meet the directives of FERC Order No. 779 for stage 1 (Operating Procedures) Standards. In the Order FERC established a January 2014 filing deadline for Stage 1 standards. Stakeholders are encouraged to review the posted material early and provide comments and recommendations for substantive issues that must be addressed to gain their support, as opportunities to revise and ballot the standard are limited.

Under the revised Standard Processes Manual approved by FERC on June 26, 2013, the EOP-010-1 initial draft standard and associated implementation plan, VRFs and VSLs are posted for a 45-day comment period, with ballot pool formation during the first 30 days, a ballot and non-binding poll during the last 10 days of the 45-day period. The SAR for this project is also posted for comment.

Background information for this project, including a link to the Operating Procedure templates developed by the GMD Task Force, can be found on the project page.

Instructions for Joining Ballot Pool

Ballots pools are being formed for EOP-010-1 (Geomagnetic Disturbance Operations) and the associated non-binding polls in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submittal of an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Initial Ballot: bp-2013-03_GMD_in@nerc.com
Non-Binding poll: bp-2013-03_GMD_1_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, August 12, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

A ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (85 Responses)
Name (53 Responses)
Organization (53 Responses)
Group Name (32 Responses)
Lead Contact (32 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (14 Responses)
Comments (85 Responses)
Question 1 (61 Responses)
Question 1 Comments (71 Responses)
Question 2 (61 Responses)
Question 2 Comments (71 Responses)
Question 3 (59 Responses)
Question 3 Comments (71 Responses)
Question 4 (59 Responses)
Question 4 Comments (71 Responses)
Question 5 (0 Responses)
Question 5 Comments (71 Responses)
Question 6 (46 Responses)
Question 6 Comments (71 Responses)
Question 7 (45 Responses)
Question 7 Comments (71 Responses)
Question 8 (45 Responses)
Question 8 Comments (71 Responses)
Question 9 (41 Responses)
Question 9 Comments (71 Responses)
Question 10 (0 Responses)
Question 10 Comments (71 Responses)

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Individual
Paul Rocha
CenterPoint Energy
Yes
CenterPoint Energy agrees in general with the SDT proposal but has an alternative suggestion for the specific roles of the applicable responsible entities. Please see CenterPoint Energy's comments regarding Requirement 1 (Question 2).
Yes
CenterPoint Energy agrees in general with proposed Requirement 1 but offers an alternative proposal on specific aspects of the Requirement. We propose that the SDT modify R1 to read as follows: Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan consisting of Operating Procedures developed by the Reliability Coordinator and coordination of GMD Operating Procedures that may be developed by individual Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. Discussion: We believe it is not necessary, beneficial, or efficient for each and every applicable Transmission Operator and Balancing Authority to try to develop GMD-related Operating Procedures and for the Reliability Coordinator to then try to harmonize multiple individual Operating Procedures in a way that benefits the region as a whole. We believe the most efficient and beneficial approach is for the Reliability Coordinator to develop an Operating Plan for the region, but allow (not require) individual Transmission Operators and Balancing Authorities to supplement the Reliability Coordinator's Operating Plan with individual Transmission Operator or Balancing Authority Operating Procedures, as along as those individual Operating Procedures, if any, are coordinated by the Reliability Coordinator. As repeatedly and correctly noted in the FERC Order, GMD assessment and mitigation requires a wide-area view. We believe some, if not most, individual Transmission Operators and Balancing Authorities will not be in a good position to reasonably determine what GMD-related operating actions would benefit the reliable operation of the entire region. Indeed, for some individual Transmission Operators and Balancing Authorities, it is possible and we believe likely that no action by that individual party is necessary or beneficial for the reliability of the region as a whole. The Reliability Coordinator has the wide-area view and is in the best position to determine what Operating Procedures would benefit the region as a whole. However, we also recognize that some individual Transmission Operators or Balancing Authorities may have already developed and implemented Operating Procedures, or may do so in the future based on

specific concerns or vulnerabilities identified at some future time. We believe that it is beneficial to allow (but not require) individual Transmission Operators and Balancing Authorities to develop individual Operating Procedures based upon that entity's detailed knowledge and assessment of its facilities, as long as provision is made for the Reliability Coordinator to coordinate such discretionary individual procedures that would supplement the regional procedures. If the SDT agrees with CenterPoint Energy's proposal, the language of R1.2 would probably need to be modified by changing "…GMD Operating Procedures of all Transmission Operators and Balancing Authorities…" to "…GMD Operating Procedures of any submitted Transmission Operators and Balancing Authorities…". Also, R3 would need to be modified. R4 and R5 would be deleted. CenterPoint Energy will discuss proposed changes to R3 in response to the next question.
No
See CenterPoint Energy's response to the previous question. In this question, the SDT states, "The draft Standard is intended to allow each entity to develop its own procedures…". There is a difference between allowing each entity to develop its own procedures and requiring each entity to do so. R3, as proposed, would do the latter. CenterPoint Energy's proposed changes to R1 would allow, but not require, an individual entity to develop its own procedures that would supplement required regional procedures developed by the Reliability Coordinator. If the SDT agrees with CenterPoint Energy's proposed change to R1, R3 would be modified to require Transmission Operators and Balancing Authorities to submit individual Operating Procedures, if any are developed, to the Reliability Coordinator so that the Reliability Coordinator could ensure coordination that would benefit the region as a whole. CenterPoint Energy also has specific concerns that R3.1 is unnecessary and unduly prescriptive. On page 24 of the FERC Order, FERC describes NERC's concern with reliance upon the most familiar means of characterizing space weather information, the "K-Index". On Page 30 of the Order, FERC acknowledged NERC's concern and took no position regarding overreliance on the K-Index to trigger operational procedures. R3.3 appropriately allows the responsible entity to choose and then document for compliance what the trigger mechanism would be, which could be space weather information or some other mechanism (GIC monitoring, for example). If an individual entity concurs with NERC's view that space weather information is an unreliable means of triggering Operating Procedures, then that entity should not be required to acquire and disseminate such information. Proposed language changes to implement CenterPoint Energy's suggestions are as follows: R3 Each Transmission Operator and Balancing Authority that chooses to develop, maintain, and implement Operating Procedures to supplement the Reliability Coordinator's Operating Plan described in R1 shall submit such supplemental Operating Procedures to the Reliability Coordinator for review and approval. 3.1 DELETED 3.2 DELETED (addressed by R1.1) 3.3 Moved to Requirement 1 as R1.3 R4 DELETED (addressed by R2) R5 DELETED
Yes
CenterPoint Energy is hopeful that the SDT will agree with CenterPoint Energy's suggested changes. With CenterPoint Energy's suggested changes, we believe this standard can be reasonably applied throughout North America. If not, we believe the proposed standard is problematic for regions that have little or no GMD-related risk and ask that the SDT consider a proposal to exclude such regions from applicability. CenterPoint Energy understands that such a proposal would be subject to the Commission's review and approval but the FERC Order is clear that the Commission understands that there are different risks in different regions and the Commission does not endorse or order a "one-size-fits-all" approach. CenterPoint Energy believes candidate regions to exclude from these requirements would potentially include ERCOT, SERC, and FRCC. However, to re-iterate our main point, we believe this standard could be applied to all regions, even those regions with minimal GMD-related risk, if CenterPoint Energy's proposed changes are accepted. Even for those regions that have more GMD-related risk than other regions, CenterPoint Energy believes it is problematic and, at best, inefficient, for each and every Transmission Operator and Balancing Authority in such regions to attempt to develop individual Operating Procedures intended to collectively enhance the reliability of the region as a whole.
Yes
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
No
Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems. Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers.
No
Suggest changing language in M1 for clarity and also to replace "implemented" with "coordinated". M1 should read: M1.

Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.
Yes
Yes
Would like clarification of the statement “last effective date” in the Table of Compliance Elements, Rows 2 and 4. Change the sentence to the following: “The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective date of the procedures”
Yes
Yes
No
Yes
MISO has business practice manuals (BPMs) that may require modifications.
If the need for mitigation is identified, it is important to coordinate the response and installation of identified mitigations between GOs and TOs.
Group
SERC OC Review Group
Stuart Goza
Yes
Yes. We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. In addition, if the original language (greater than 200kV), remains in the standard, there should be an exception for equipment such as transformers.
Yes
Language should be added to ensure coordination between adjacent RCs.
Yes
Yes
Yes
Yes
There is a possibility that the DP would be included because the 200 kV limit may include distribution equipment. The SDT should consider raising the “bright line” to 300 kV.
The industry is developing the necessary procedures, processes and analysis tools to support the GMD standard. As these technologies evolve the industry will make modifications to address those changes. SDT should consider and ensure that entities have adequate time to conduct analyses based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology.
Until analysis is underway there is a possibility that Reliability Emergency Procedures and market operations may require modification.
Thank you for the opportunity to comment. Disclaimer: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
John Falsey

Invenergy LLC
Agree
Individual
Thomas Foltz
American Electric Power
Yes
No
R1, 1.2 We are concerned by requiring the RC to “coordinate” Operating Procedures, and determine their collective compatibility. Exactly what actions would demonstrate coordination, and how could compliance of it be proven or shown? The word “coordinate” is very subject to interpretation, and could be inconsistently applied in various audits. R1.2 states that the GMD Operating Plan shall include “A process for the RC to determine that the GMD Operating Procedures … are coordinated and compatible.” This could potentially result in different coordination requirements in different regions and consequently, prevent entities who are operating in multiple regions to use consistent procedures within an entity’s service territory.
Yes
No
Requirements R2 and R4 state that each applicable entity shall review its GMD Operating Plan/Procedures every 36 months from the last *effective* date while Requirement 5 states that the applicable entities shall have a copy of its GMD Operating Procedures in the control room(s) prior to its *implementation* date. AEP recommends referencing the effective date only. R5 should be changed to state “…shall have a hard or electronic copy of its GMD Operating Procedures…”
In the VSL matrix, R4 states that “the responsible entity reviewed its GMD Operating Procedures and submitted them for approval….”. Requirement 4, as stated, does not require approval for the Operating Procedures, therefore the words “and submitted them for approval” should be deleted from all four VSLs for R4.
Yes
Yes
No
Yes
The SAR indicates that there may be changes to additional standards eventually proposed as a result of Stage 2 project efforts. There is no mention of any specific modifications or additional requirements related to the sharing of GMD-related modeling information. A library of GIC models capturing various system conditions will eventually be necessary. There should be a similar coordinated effort in developing such a GIC model library as the MMWG that develops power flow and stability models on an annual basis.
AEP is voting negative on this draft, but can foresee voting in the affirmative if the issues and concerns expressed in this response are addressed in future versions of the draft.
Individual
John Bee
Exelon and its Affiliates
Yes
Yes
Yes
R3.3, font is incorrect – need the entire number to be bold.
No
Exelon believes that performing a review of GMD Plans / Operating Procedures every 36 months is contrary to the Paragraph 81 criteria whose effort was to remove truly administrative requirements that do not have an impact on electric grid reliability. We feel tha R2, M2 and R2, M4 should be removed.

Individual
Nazra Gladu
Manitoba Hydro
Yes
No
(1) R 1.1: This requirement needs clarification. It refers to a GMD Operating Plan requiring “a description of activities designed to mitigate the effects of GMD events….”. It is not clear whether the “activities” are intended to be performed by the Reliability Coordinator or refer to the Operating Procedures of the Transmission Operators / Balancing Authorities, or some other type of activity directed by the Reliability Coordinator, but performed by other entities. FERC Order 779 only referred to a possible “coordination “ of Operating Procedures and that element is captured separately in R 1.2. (2) R 1.2: The requirement for “compatibility” of Operating Procedures causes concern and should be deleted. FERC Order 779 (Par. 38) specified that GMD standards “should allow responsible entities to tailor their operational procedures based on the responsible entity’s assessment of entity-specific factors, such as geography, geology and system topology. While FERC also directed NERC to consider the “coordination” of such operational procedures, it did not require the “compatibility” of such procedures. Manitoba Hydro already has in place operating procedures to respond to GMD events. The role of Manitoba Hydro’s Reliability Coordinator is to notify Manitoba Hydro of GMD events and disseminate information on present and forecasted storm levels. This would be appropriately viewed as coordination. However, requiring a Reliability Coordinator to determine the “compatibility” of several entities’ Operating Procedures goes beyond coordination and begs the question of what happens if there is a determination that certain Operating Procedures are not compatible. Does the Reliability Coordinator have the authority to direct an entity to adopt a different procedure? If so, it is not clear how it would be determined which responsible entity must change its procedures. Most importantly, this requirement erodes the discretion that was granted to Transmission Operators and Balancing Authorities under Order 779.
(1) Background - for clarity, consider replacing the words “can lead to” with [may result in]. (2) Purpose - for clarity, consider replacing the purpose section of the standard with the following sentence: “To [ensure plans, operating procedures, and resources are maintained and available] to mitigate the effects of geomagnetic disturbance (GMD) [emergencies on the bulk electric system.]” (3) M2 - consider revising the measure as follows: “Each Reliability Coordinator shall have evidence [showing] that it has reviewed its GMD Operating Plan within the timeframe of Requirement R2. [Acceptable evidence could] include a dated review signature sheet or revision history.” (4) 3.1, 3.2 and 3.3 - for completeness, start the sentance with [A listing of the]. (5) M4 - consider revising the measure as follows: “Each Transmission Operator and Balancing Authority shall have evidence [showing] that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4. [Acceptable evidence could include] a dated review signature sheet or revision history.” (6) Table of Compliance Elements, R2, Low, Medium, High VSL - insert the word [last] before the words “effective date” for consistency with Requirement R2. (7) Some entities may reduce exports to neighbors as a mitigating strategy. This method, determined to be the ideal action, based on system studies, may be perceived as potentially impacting neighbouring entities. What level of coordination would be required or appropriate to permit the curtailment of exports?
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
Should only apply to transformers which are part of BES. BES definition is based upon the low side winding voltage of greater than 100 kV where as this requirement is based upon high side voltage. Thus, this goes beyond BES elements. We suggest it apply to transformer with low side winding voltage of 200 kV or greater.
Yes

No
Requirment 3.2 requires coordination with Reliability coordinator’s plan. Thus, there should be a provision that this requirement is effective only 6 months after the Reliability coordinator’s plan is available.
No
Requirement R5 is unnecessary and should be deleted altogether. This requirement is a process and not a standard and it is not necessary to have a hard copy when an electronic copy could be readily available. There is no reliability benefit to this requirement.
Implementation time for BA and TOP should have 6 additional months than the implementation time for Reliability coordinator. This is to allow coordination wiht Reliability Coordinator’s procedures affecting BA and TOP. Requirement R1, 1.2 should have the word “all” deleted. It does not serve any specific purpose and could become unnecessarily burdensome.
No
No
Group
Salt River Project
Bob Steiger
Yes
We agree that the scope is appropriate.
No
We believe that the requirement should state that the Reliability Coordinator should establish triggers that are appropriate for the given geographical and system exposure for each TO or BA. We would suggest language such as the following: R1.1 The Reliability Coordinator shall create a preliminary assessment of the exposure for each BA and TO. The plan and procedures developed by the Reliability Coordinator shall establish trigger levels for initiating and terminating these plans or procedures based on the preliminary assessment of exposure for each BA or TO.
No
Please see Comment for question 2. The requirements for the Reliability Coordinator should be the same for the Transmission Operator and Balancing Authority.
Yes
A general comment on the Solar Cycle. It seems that the timing of the peak of the solar cycle might require more frequent review of plans and procedures.
Yes
Yes
Yes
Yes
Depending on how the Reliability Coordinator writes the plan and procedures there could be an impact to elements of the BES that are jointly owned, mainly regarding contractual requirements.
We believe the standard needs to address shared elements of the BES. The exposure at one end of a shared element may be more significant than at the remote end. NERC and the Reliability Coordinator need to provide direction when this type of situation occurs.
Individual
Joe O'Brien for Ed Mackowicz
NIPSCO
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems.

These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, the TOP should not be required to have plans specifically for GMD events.
Yes
Yes
Yes
Yes
If the geological conditions and system configuration are such that damaging magintudes of GIC do not exist and there is no history of GIC induced damage or misoperation in the TOP’s service area, it should not be required to have plans specifically for GMD events.
No
Individual
Steve Hill
Northern California Power Agency
Yes
For Stage 1 I believe the SDT has it correct; however I am concerned that there is no mention as to what will happen with IRO-005-3.1a R3 which appplies to a host of registrations. At some point EOP-010-1 will supercede IRO-005-3.1a, but no mention in the implementation plan is discussed.
No
I think there is too much latitude given. The guidance document describes GMD as more a global issue; not just a regional issue. I believe the guidance document provides a good list of activities for an RC to start with, but that these activities should be consistent between various RCs as well as the process the RCs will use to determimne if the TOP and BAs are coordinated and compatible.
No
In a perfect world this should already exist is folks are truely in compliance with IRO-005-3.1a R3. How are the RCs, TOPs and Bas curently complying with IRO-005-3a? This might provide some insight for the SDT.
Yes
Yes, but I do not see that this is any different form complying with IRO-005-3 R3 except for the 36 month review cycle.
To suumarize: I will vote no on the initial ballot per comments I have submitted; however that does not mean I am opposed to this standard. I do believe GMD is an issue that even though it is low frequency can have an reliabiilty impact on the BES or BPS. I believe the SDT needs to address the IRO-005-3 R3 concern I have discussed. If I were to guess the reason for EOP-010-1, it would be to replace a pretty loose requirement in IRO-005-3 R3. If this is the case then give more direction and guidance in the new standard per the guidance document that NERC provided
Yes
I like the SAR; too bad some of the language did not carry over into the implementation plan
Yes

No
No, but not sure I understand what you are getting at. As stated above geology and soil conditions will vary from region to region
Yes
Operating procedures that address compliance with IRO-005-3 R3 will need to be modified and new procedure to show compliance with EOP-010-1 will need to be developed.
No further comments
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
Yes
Yes
Yes
Yes
No
No
If the need for mitigation is identified, ATC believes that it is important to coordinate the response and installation of identified mitigations between GOs and TOs.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
No
Requirements R2 and R4 t to review the plan is purely administrative. As the scientific knowledge evelves R1 and R3 requires a plan to be designed to mitigate the effects of GMD.
Requirement R5 to make the operating plan available in the control center is administrative. Reliability requires the plan to be implemented as described in requirement R1. VRF for R1 and R3 are Medium since an entity failure to implement the GMD operating plan may lead to cascade. VRF for R2, R4, and R5 should be Low. R2, R4, and R5 are purely administrative. The entity is required to have Operating Plans that mitigate the effects of GMD a review of the operating plan is a secondary activity to developing, maintaining, and implementing an operating plan.

Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
Yes
We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a.
Yes
Requirements R2 and R4 could easily be combined. Is there a specific reason why the Reliability Coordinator is separated from the Transmittion Operator and the Balancing Authority? The wording in these two requirements is identical.
1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5. If Requirement R5 was to be retained, we suggest adding “Reliability Coordinator” after “Transmission Operator” and “Balancing Authority”. We believe that Reliability Coordinators should also have a copy of their GMD Operating Procedures in their primary and backup control rooms. The current Requirement R5 does not include the Reliability Coordinator. 2. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”. The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
No
The Stage II assessment should be done at the interconnection level, not by a patchwork of the Planning Coordinators and Transmission Planners. If analysis shows there are potential local issues, NERC should consider regional criteria or local procedures first, rather than an overly complex standard, much of which won’t apply to most entities interonncetion-wide.
Yes
No
No
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
Recommend adding “BES” as qualifier for transformer. 4.1.1 Reliability Coordinator 4.1.2 Balancing Authority with a Balancing Authority Area that includes any BES transformer with high side terminal voltage greater than 200 kV 4.1.3 Transmission Operator with a Transmission Operator Area that includes any BES transformer with high side terminal voltage greater than 200 kV
Yes
Yes

No
Requirement R5 seems administrative in nature (similar to other Paragraph 81 requirements) and seems duplicative of R3 which already requires implementation of the Operating Procedures (i.e. implementation could include making operation personnel aware of the Operating Procedure and having available). If a separate training requirement is developed, R5 would be further redundant. Recommend that R5 be removed. Requirement R2 and R4 require applicable entities to review their GMD Plans/Operating Procedures every 36-months. With solar cycles having an average duration of about 11 years and the Plan and Operating Procedure being potentially utilized 1-2 years during the peak years of the 11 year cycle, how was the 36 month review criteria reached? Recommend changing to a 48 month review period which still allows for 2-3 reviews during a 11 year solar cycle.
Yes
Suggest that any associated training requirements for System Operators be deferred to Stage 2. Based on what is learned from Stage 2 benchmark events, may want to revisited functional applicability of Stage 1 (i.e. EOP-010).
Yes
No
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
There may be cases in which a transformer with a high side terminal voltage of greater than 200 kV is not considered BES (e.g., the transformer is excluded as part of a local network). ReliabilityFirst requests clarification whether this non-BES transformer is included within the scope of the standard?
Yes
Yes
Yes
1)Requirement R2 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan” at the end of the requirement. ReliabilityFirst suggests the following for the SDTs consideration: "Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date [of its GMD Operating Plan]." 2) Requirement R4 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan.” ReliabilityFirst suggests the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date [of its GMD Operating Procedures]."
1) Requirement R5 - To be consistent with the language in the other requirements within the standard, ReliabilityFirst recommends changing the term “implementation date” to “effective date.” ReliabilityFirst offers the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its [effective] date." 2) Consideration for new Requirement R6 - ReliabilityFirst recommends including a new Requirement R6 which would require adjacent Reliability Coordinators to share their respective GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators should be aware of each other’s GMD Operating Plans. 3) VSL Requirement R2 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "…but less than or equal to…" language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than [or equal to] 39 months, since the effective date." 4) VSL Requirement R4 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "…but less than or equal to…" language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than [or equal to] 39 months, since the last effective date."
Yes
Yes

Yes
No
Group
Hydro One Networks Inc.
Sasa Maljukan
Yes
Yes
Yes
No
Requirement R5 is of a purely administrative nature, not contributing to reliability. Suggest to eliminate. Emphasis and focus should be in operating personnel training and awareness. If R5 is kept in the standard, request to clarify the meaning of “prior to its implementation date.” We believe it should be “prior to actions to implement the plan.” As written in could be misinterpreted as prior to the standard effective date.
There is a GMD related pre-existing requirement in IRO-005-3.1a R3. It seems, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”.The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
No
Suggest adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR. If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard?The disposition of IRO-005-3.1a R3 needs to be addressed in the SAR as a retirement.
Yes
Yes
The flexibility in the plan design takes into account locational differences, which are geographically and geologically based. There is no basis for differences due to regional entity boundaries.
Yes
Individual
Martyn Turner
LCRA Transmission Services Corp
No
The standard has not provided a clear reason for starting at 200 kV, which seems arbitrary. Papers on GMD do indicate the potential risk to transformer’s increases at the higher voltage levels and in particular to single phase wye connected transformers. Would propose the following: 4.1.3.1 a Transmission Operator Area that includes any BES transformer with three single phase core windings connected in a "wye" configuration of 300 kV or greater; or 4.1.3.2 a Transmission Operator Area that includes any BES transformer with at least one "wye" connected winding greater than 400 kV;
Yes
Yes
Yes

none
no comment
no comment
Yes
The standard and SAR as drafted do not address differences in geography, geology or system topology variances. For example because of its southern latitude, the ERCOT region is over 10 times less likely to be impacted by a GMD occurrence than northern regions of the country and 100 times less than regions of Canada. The cost and effort of prevention measures should be in line with the potential risks.
no comment
no comment
Individual
Michiko Sell
Public Utility District No. 2 of Grant County, WA
Yes
Yes
Yes
Yes
GCPD is concerned about the implementation period being sufficient to allow the RC to develop and implement a GMD Operating Plan AND afford adequate time to ensure that each TO and BA within its region the ability to develop, maintain and implement GMD Operating Procedures that are coordinated with the RC's GMD Operating Plan. Six (6) months is not sufficient time to allow development and coordination within the region.
Group
Dominion
Connie Lowe
Yes
Yes
Yes
No
As R2 and R4 are currently written, they are purely administrative and do nothing to improve or insure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.
Yes
Dominion suggests adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR? If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard.
Yes
No
No

Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Agree
SERC OC Review Group
Individual
Ben Li
Ben Li Associates
Yes
Yes
Yes
1. We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a. 2. It R3 is to be retained, then it does not mention “applicable” BAs and TOPs, which it should. Further, a BA or TOP should be able to adopt a template procedure developed by its Reliability Coordinator. This should be explained in an administrative appendix to the standard.
Yes
1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5. 2. GMDs are an emerging issue. There is nothing in this standard that enables information sharing and learning. The RC plan and BA/TOP procedures should include what sensing information is in the field and the general reporting that such information gathering is done when GIC symptoms are observed. There should also be information collected following major solar events that is evaluated by the NERC technical committees. This should not be codified in the requirements, but in an administrative appendix or an activity to be included in events analysis.
No
The Stage II assessment should be done at the interconnection level, not by a patchwork of the Planning Coordinators and Transmission Planners. If analysis shows there are potential local issues, NERC should consider regional criteria or local procedures first, rather than an overly complex standard, much of which won’t apply to most entities interconnection-wide.
Yes
No
Yes
There is a possibility that the procedure of one RC could end up causing redispatch or reconfiguration in a TOP or BA area or another RC area. There is also a need to address the mechanism for cost recovery, particularly when the problem could be mitigated locally through upgrades. The cost recovery for redispatch and/or upgrades to BES facilities needamong affected entities.
Individual
Don Schmit
Nebraska Public Power District
Agree
Southwest Power Pool (SPP)
Group
seattle city light

paul haase
No
Seattle City Light supports the general concepts presented in the draft Standard and appreciates that the Standard Drafting Team affords each entity flexibility as to procedures. However, Seattle is concerned about the broad applicability of the Standard as proposed, and recommends that it only apply to BA and TOPs with Bulk Electric System (BES) transformers 200kV and above (as well as all RCs). This change would make this Standard consistent with other Standards as well as the BES definition we've worked so hard on the past several years.
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Yes
The Applicability and Purpose conflict however. The Purpose says "To mitigate the effects of geomagnetic disturbances (GMD) events by implementing operating procedures." But the Standard's Purpose is not consistent with the Standard. The Standard goes into detail about the mitigation plans. Recommend the Purpose be "To establish and implement GMD mitigation operating procedures". The effectiveness of these procedures to mitigate the effects of GMD is unknown.
Yes
Yes
No
The review interval specified in R2 and R4 is 36 months. A five year review would be more appropriate given the length of the solar cycle. As R2 and R4 are currently written, they are purely administrative and do nothing to improve or ensure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis. Requirement R5 also is administrative, does not contribute to reliability, and can be eliminated. Suggest to eliminate the wording "All procedures should be at the primary and backup control center as part of normal business". Emphasis and focus should be on operating personnel training and awareness. If it is decided to keep R5 in the Standard, request clarificiation of the meaning of "prior to its implementation date." It should be "prior to actions to implement the plan." As written it could be misinterpreted as prior to the Standard's effective date.
There is a GMD related pre-existing requirement in IRO-005-3.1a R3. The implementation plan is not clear regarding the retirement of the requirement. It would seem, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF. Simpler wording would make the Standard easier to understand. Every plan will be different depending upon a wide range of factors affecting GMD mitigation; equipment types and inventory, location, system configuration and topography, latitude, ground characteristics, etc. Suggest the following simplifying wording changes to Requirement R3: R3. Each Transmission Operator and Balancing Authority shall develop, maintain, and implement GMD Operating Procedures. At a minimum, the Operating Procedures shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning] 3.1. The steps or tasks for the acquisition and dissemination of space weather information to its System Operators. 3.2. The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan. 3.3 The predetermined trigger conditions for initiating and terminating steps or tasks in the Operating Procedure. To be consistent with the terminology in other standards, suggest changing the wording the Applicability Section to: 4.1.2 Balancing Authority with a Balancing Authority Area that includes transformers with high voltage terminals connected at 200kV and above. 4.1.3 Transmission Operator with a Transmission Operator Area that includes transformers with high voltage terminals connected at 200kV and above. The wording of the Purpose should be changed to "To mitigate the risk of instability, uncontrolled separation, and Cascading in the Bulk-Power System as a result of geomagnetic disturbance (GMD) events by developing, maintaining and implementing Operating Plans and Operating Procedures." The Purpose as written should state what GMD affects. It also

only addresses the implementation of the Operating Procedures but does not address the development and maintenance aspect, nor does it address the Operating Plans.
No
Suggest adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR. If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard? The disposition of IRO-005-3.1a R3 needs to be addressed in the SAR as a retirement.
Yes
Yes
The flexibility in the plan design takes into account locational differences, which are geographically and geologically based. There is no basis for differences due to regional entity boundaries.
Yes
Studies, control room practices and monitoring all will be needed. These are business practice changes and have a cost which should be considered in this Standard's development. It should be.
The Standard is a reasonable response to the FERC Directives. When EOP-010-1 becomes effective IRO-005-3a Requirement R3 becomes redundant and should be removed. This information should be added to the "Related Standards" section of the SAR.
Individual
Silvia Parada Mitchell
NextEra Energy
No
NextEra Energy is pleased with the work the GMD SDT has done in a very quick period of time, with the exception of adding certain requirements that no longer fit within the paradigm under which Standards are to be drafted. NextEra suspects that these requirements were added because of the short period of time in which the SDT drafted the Standard, and, thus, NextEra is hopeful that once highlighted here that the SDT will quickly decide to delete the requirements as they are inconsistent with current Standard drafting practices. These requirements are inconsistent with both results based and P81 concepts, given that they are administrative in nature and do little to promote reliability. While some may see these requirements as good practices, adding them is no longer consistent with Standard drafting practices nor desired by stakeholders. New Standards are to be clear, high quality, technically sound and results based. Also, these requirements are similar to those that FERC recently indicated it would approve for retirement in the P81 Notice of Proposed Rulemaking. Therefore, NextEra requests that these requirements, noted below, be deleted. R2. Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. R4. Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date.
For the same reasons provided in response to question number #4 (P81 -- administrative in nature), NextEra requests that the following requirement be deleted: R5. Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
Tri-State believes that Balancing Authorities should not be included as an applicable entity because there will be unnecessary duplication or conflict between the BA and the Reliability Coordinator Operating Plans.
No
Tri-State believes that the proposed standard, as written, is too vague and gives the Reliability Coordinator too much latitude to create plans as only it deems appropriate. It also does not provide for industry review of these plans beforehand. Requirement R1 appears to be a "fill in the blank" requirement, which FERC does not approve.

Yes
Tri-State agrees that R3 properly addressed FERC Order No. 779, but believes the implementation periods should be modified. A 6 month implementation period requiring the Reliability Coordinator to develop the Operating Plan and the Transmission Operator/Balancing Authority to develop the Operating Procedures is not suitable. The Transmission Operator/Balancing Authority needs time to ensure their procedures are in accordance with the Reliability Coordinator's Operating Plan so the implementation dates need to be staggered.
Yes
1. Tri-State believes a 6 month implementation period isn't appropriate for this. This implementation period requires the RC to develop the Operating Plan and the TOP/BA to develop the Operating Procedures at the same time. The TOP/BA needs time to ensure their procedures are in line with the RC's Operating Plan so the implementation dates need to be staggered. 2. Tri-State also believes Stage 1 and Stage 2 should be reversed. Developing, maintaining, and implementing a plan without first conducting assessments and determining the risk is illogical. The Operating Plans should be based on the results shown of the assessments. 3. There is a lack of evidence showing major damage and widespread outages due to a geomagnetic disturbance. There should be more studies performed before creating a Reliability Standard in order to better determine the actual necessity of one. 4. Currently, Tri-State believes that a guidance document would be a better solution to address the risk of potential geomagnetic disturbances. 5. Tri-State believes all non-BES transformers should be excluded regardless of high side voltage. In addition any transformer with a delta primary winding should be excluded regardless of the high side voltage.
Yes
Tri-State believes the SAR provides a scope to address the directives but still strongly believe that Stage 1 and Stage 2 should be in the reverse order. An assessment should be conducted to determine potential impacts from GMD events prior to developing Operating Procedures to mitigate any possible effects of GMD.
No
Tri-State believes that BAs should not be included as an applicable entity because there will be unnecessary duplication or conflict between the Balancing Authority and the Reliability Coordinator Operating Plans.
Yes
The assessments from each region will likely provide different results due to the varying geography, geology and location. A continent-wide standard will not properly or efficiently address the potential risks brought by geomagnetically induced currents. Tri-State believes that NERC should issue an alert to have the different Regional Entities review and develop regional standards, guidelines or other criteria to mitigate the possible effects of geomagnetic disturbances rather than develop a "fill in the blank" standard.
Yes
The NERC IRO-005-3.1a Requirement 3 may need to be retired and incorporated into the new standard(s). The WECC Geo-Magnetic Disturbance Reporting procedure, which meets the above NERC requirement, may also need to be modified. It is extremely difficult to determine whether internal business practices will need to be adapted prior to assessments being performed to identify potential impacts of GMD events. The final GMD Operating Plan(s) developed by the Reliability Coordinator and Balancing Authorities, which have not been developed, could also impact internal business practices.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
Yes
Western Area Power Administration (WAPA) and the Bureau of Reclamation (Reclamation) believe that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
No
WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation believe it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending

on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address “The steps or tasks for receiving and disseminating space weather information to its System Operators.”
Yes
: WAPA and Reclamation also believe Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
Yes
Yes
Yes
Yes
Individual
Jack Stamper
Clark Public Utilities
Agree
Snohomish County Public Utility District
Group
Western Electricity Coordinating Council
Steve Rueckert
Florida Municipal Power Agency
No
See FMPA concerns on aplicability, type of transformer, and whether or not the BA should be an applicable entity.
Yes
Requirement is acceptable, but implementaiton period is too short
Question applicability of BA and implementation period is too short
Yes
Six Month implementation period is not adequate
Yes
No
I am not aware of any regional variances that would be needed but do have concern about entities in the far south being subject to these standard prior to studies being conducted.
No
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
No
SNPD agrees in general but believes the 200 kV voltage threshold is premature. In general, we believe that GMD should be tackled on a regional basis and already by the Reliability Coordinator (“RC”). It is our understanding that location (latitude and local geology) and the type of systems (i.e., systems with extra-high-voltage, series capacitor compensated lines, transformer configuration & grounding, and line length) are important elements in a GMD analysis. Therefore, a one-size-

fits-all approach based on voltage level would be inappropriate. SNPD believes the Reliability Coordinator (“RC”) would be in the best position to identify facilities including the appropriate voltage level or other attributes that may become more apparent as research in this area matures.
Yes
Appropriate implementation time should be given so that the RC has time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions. Although GMD and Geomagnetically Induced Currents (“GIC”) have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufactures. Recent work presented at the 2013 IEEE PES General meeting by Emanuel Bernabeu, Dominion “Overview of GMD Phenomena and ways to study the impact on the transmission system” and Ramsis Girgis, ABB “Equipment issues transformers, (Major Concern)'s etc. -from the transformers committee, impacts on transformer fleet and new designs” will provide more insight into appropriate actions to be taken by the RC and impacted functions. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on how GMD can impact the BES and what level of risk does GMD pose compared to other adverse impact events. See IEEE Power & Energy article “Geomagnetic Disturbances” by IEEE Power and Energy Society Technical Council Task Force on Geomagnetic Disturbances, July/August 2013 pg. 71-78.
No
Because GMD can be a wide area event the BA and TOP efforts should focus on coordinating operations and procedures with the RC. Also GMD is a High-Impact, Low-Frequency event so overall risk to the TOP or BA area should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
Yes
Yes
Yes
No
No
Individual
Rich Salgo
NV Energy
No
The preparation and execution of operating procedures to mitigate the effects of GMD events on the power system are specific to the Reliability Coordinator and the Transmission Operator entities. We do not believe that actions are required of the Balancing Authority function at all, as this is not a balancing issue, but rather a transmission operations issue. Additionally, we believe the scope of applicability should not reach into distribution transformers, particularly radial transformers serving distribution load. Hence, we recommend that the Applicability section be modified to remove 4.1.2 (Balancing Authority) and place a limitation on 4.1.3 to restrict applicability to BES transformers of the indicated voltage range.
No
Requiring the RC to develop and maintain a plan is an appropriate requirement; however, it is unclear what the RC must do under 1.2 to "determine" that the GMD Operating Procedures in its area are coordinated and compatible. Suggest a language change to "A process for the RC to review and coordinate the GMD Operating Procedures of all TOP's in the RC Area."
No
OK, except "Balancing Authority" should be removed from R3.
Yes
Agree with the 36 month cycle of review; however, BA should be removed from R4.
No
No, as discussed in response to Q1, the BA should have no direct functional responsibility for the mitigation of GMD. This should be up to the TOP's within the BA footprint. Inclusion of the BA complicates the situation.

No
No
Individual
Jen Fiegel
Oncor Electric Delivery Complany LLC
No
The draft fails to include Generator Owners and Generator Operators that have step-up and auxillary transformers with a terminal higher that 200 kV. If GMD causes unintended ground induced currents (GICs) on Transmission Owners' and Transmission Operators Transmission Transformers that are important to the grid, then it stands to reason that step-up and auxillary transformers are at risk as well. Generator Owners transformers have a great impact to the reliability of the system. Those transformers need to be included in the Standard. Additionally, it would seem imperative to include generator owner transformers that supply offsite power to nuclear generation that are above 200 kV. The Standard must include the GO and GOP in order to address the FERC Order.
No
The proposed language of R1 assumes all Regions operate the same therefore in order to support the structure of Regions across the North American utility industry, Oncor recommends R1 be revisedto: "Each Reliability Coordinator shall coordinate the development and maintain a GMD Operating Plan with its Balancing Authority, Transmission Owners, Transmission Operators, Generator Owners, and Generator Operators that coordinate GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:" Oncor believes the RC should remain responsible for implementing the plan.
Yes
Yes
No
The Standard did not address all owners and operators of equipment associated with the FERC Order directing NERC to "submit for approval one or more Reliability Standards that require owners and operators to develop and implement operational procedures to mitigate the effects of GMDs." The Standard needs to also include Generation Owners and Operators of step-up transformers and auxillary transformers with at least one terminal at 200 kV or higher.
No
The Standard did not address all owners and operators of equipment associated with the FERC Order directing NERC to "submit for approval one or more Reliability Standards that require owners and operators to develop and implement operational procedures to mitigate the effects of GMDs." The Standard needs to also include Generation Owners and Operators of step-up transformers and auxillary transformers with at least one terminal at 200 kV or higher.
No
No
Individual
Oliver Burke
Entergy Services, Inc.
Yes
We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. One of the reasons for the change is due to the number of transmission to distribution transformers where the high side voltage is 230 kV. On the other hand, having the 200 kV cutoff has the potential to create confusion for BA. A BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces.
Yes
Language should be added to ensure coordination between adjacent RCs.

No
As mentioned in Q1, a BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces and may need to develop, maintain, and implement GMD Operating Procedures. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
No
R5 is an administrative requirement for which compliance may be unprovable. This requirement (to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms) is also redundant to PER-005, which requires a Job Task Analysis for every task performed by System Operators. All administrative requirements should be deleted.
Yes
Yes
DP may need to be included as the 200 kV limit may include distribution equipment. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
No
SDT should consider and ensure that entities have adequate time to conduct analyses based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology.
Until analysis is underway there is a possibility that Reliability Emergency Procedures and market operations may require modification.
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC OC Review Group
Individual
Dan Inman
Minnkota Power Cooperative, INC.
No
Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV and smaller, high impedance non-BES transformers serving load. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems. Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV and a base rating of at least XX MVA". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers. The addition of “XX MVA” will limit the inclusion of small 200+ kV connected transformers. It is unclear as to what that limit should be and the evidence for that limit is unknown. Alternatively, could make the statement “includes BES power transformers with a high side terminal voltage greater than 200 kV” but this could exclude large load serving transformers that do have a significant effect in relation to GMD events.
No
Comment #1) Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read: M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement. Comment #2) Suggest replacing the word “all” in R1.2 to “applicable”. Rationale: Using the word “all” could be interpreted such that TO’s and BA’s that have transformers below 200kV could be affected. Replacing “all” with “applicable” would avoid confusion, and be in alignment with the SDT intent.
Yes
Yes
See NSRF Comments
Yes

Yes
No
Yes
MISO has business practice manuals (BPMs) that may require modifications.
See NSRF's Comments
Individual
Terry Baker
PRPA
Agree
Florida Power & Light
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
During the July 30, 2013 GMD webinar, the response to one question was that the SDT would consider whether the BA applicability is appropriate. Austin Energy (AE) would encourage the SDT to complete that effort.
Yes
No
Austin Energy (AE) believes that staggered enforcement dates between R1 and R3 are necessary for TOPs and BAs to develop Operating Procedures “that are coordinated with [their] Reliability Coordinator’s GMD Operating Plan.” The current implementation plan establishes a single date for all requirements. During the webinar, AE suggested this and the response was that NERC anticipates that TOPs' Operating Procedures will be developed first so the timing is acceptable. Given the definitions of Operating Plan and Operating Procedures in the NERC Glossary, AE understands how an Operating Plan can be built based on a series of underlying Operating Procedures, but if that is the intended order of operation, R3 should not require that Operating Procedures be coordinated with the RC’s Operating Plan.
Yes
Overall, AE has voted negative because there is an abundance of cleanup work necessary. AE asks the SDT to consider the comments above as well as the following points: (1) The SDT should more carefully consider the wording for the applicability of transformers. During the webinar, someone asked if the intent was to cover only BES tranformers and Mark Olsen answered in the affirmative. As written, the BES definition considers the low-side voltage (greater than or equal to 100 kV), whereas the Applicability section of EOP-010-1 considers only the high-side voltage. There could be transformers that are 69/230 kV that would not be BES Elements but would bring in a TOP or BA given the way 4.1.2 and 4.1.3 are currently written. Additionally, the SDT should consider transformers with high and low-side voltages greater than 100kV but excluded from the BES based on a documented exclusion or exception. (2) Given the requirement to “develop, maintain and implement” in R1 and R3, the SDT should consider adding in the same day operations time horizon to cover the "implement" action. (3) The SDT should clarify what is intended by “implement” in R1 and R3. During the webinar, the response to this question was unclear. SDTs on other recent projects (COM-003-1, for example) have gone to great lengths to define what is meant by "implement." RSAWs often state it means to include in your company’s body of operating procedures. Without explanation, a CEA might interpret implement as follow your Plan/Procedure exactly as written. The industry needs to know the SDT’s intent. (4) Change the word “all” to “applicable” before the phrase “Transmission Operators and Balancing Authorities” in R1 part 1.2. (5) The SDT should move the requirement regarding space weather (currently R3 part 3.1) to R1 so the RC can, in its coordination role, ensure that input data is consistent and applicable to its Region.
Yes
Yes
No
Not at this time. We believe, however, that due to geographic differences, entities in the ERCOT Region may request regional variances after we begin developing our approach to GMD.
No

Group
Oklahoma Gas & Electric
Terri Pyle
No
This standard should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Yes
No
This standard should not be applicable to the Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Yes
We agree with the language of these three requirements, however, we believe that the Violation Risk Factor should be LOWER, not Medium for these documentation related requirements.
While we understand the good intentions of FERC in Order No. 779, we feel that industry’s time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
No
This SAR should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation; and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
No
This SAR should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation; and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
No
No
While we understand the good intentions of FERC in Order No. 779, we feel that industry’s time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
Individual
Texas Reliability Entity
Texas Reliability Entity
No
We agree with the RC and TOP functions. The SDT may also want to consider adding the GOP function so that large GSU’s are also monitored under this standard.
No
This wording in R1 and R3 are “fill-in-the-blank” type of requirements that NERC has been trying to move away from. We understand that Phase 2 of the GMD Standard project will provide additional details and clarification.
No
See comments for #2 above.
Yes

Many new Standards have a Guidelines and Technical Basis section as part of the Standard. Would the SDT consider creating a Guidelines and Technical Basis section?
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the efforts of the SDT and, in general, we believe the standard is good. However, we believe the Applicability of the standard needs improvement; and that is the primary reason we are voting Negative. The ORNL report, which FMPA believes is already unreasonably pessimistic, made several conclusions that are not reflected in the applicability that FMPA believes ought to be: 1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down trasformers to distribution. 2. The winding(s) in question needs to be grounded wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with grounded wye connected winding(s) above a certain threshold voltage 3. According the the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers. 4. The primary concerns for GIC is for voltage collapse or relay misoperation due to increased MVAR demand of transformers that could potentially result in cascading, and potential damage to transformers (see SAR description of Industry Need); hence, the applicability should not be to BAs but only RCs and TOPs (see additional discussion in response to question 3). 5. FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. Almost all 230 kV transformers are 3 phase / 3 leg core transformers with a much lower probability of becoming saturated; whereas, according to ORNL, about 15% of 345 kV transformers are single phase transformers (Figure 1-19). In addition, the resistance ot 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line. FMPA assumes that GSU's owned by the GO and operated by the GOP is intended to be included in the applicability (since the vast majority of GSU's are grounded wye connected on the high side), but under the interconnecting TOP's operating plan. However, the applicability does not reflect this. If the intent of the SDT is to include these GSUs, then the applicability ought to be changed accordingly. As such, FMPA suggests the following for applicability: 4.1. Functional Entities: 4.1.1 Reliability Coordinator 4.1.3 Transmission Operator with a: 4.1.3.1 Transmission Operator Area that includes any BES transformer with three single phase transformers connected in a grounded wye configuration of 300 kV or greater; or 4.1.3.2 Transmission Operator Area that includes any BES transformer with at least one grounded wye connected winding greater than 400 kV (either three single phase transformers or a three phase transformer); or 4.1.3.3 Transmission Operator Area that interconnects with any generator interconnection facilities that include a GSU that meets either criteria 4.1.3.1 or 4.1.3.2
No
Bullet 1.2 puts RC's in a position of responsibility without authority, or at least implies such. The bullet requires the RC to "determine" that the plans of the BAs and TOPs are coordinated. What happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? FMPA suggests looking at the EOP-006 and EOP-005 construct for guidance. And as stated in response to question 1, the BA should not be an applicable entity.
No
As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority within the standards to require that additional unit commitment or redispatch.
Yes
Although FMPA agrees with a 3 year period, FMPA would prefer a requirement of once every 3 calendar years as opposed to 36 months to allow more flexibility in scheduling. Again, the BA should not be an applicable entity.
Yes

Yes
Yes
Florida is not susceptible to high GIC due to latitude and geology. At minimum, the applicability of the stadnrd ought to change based on geography and geology, e.g., maybe Florida’s applicability is only for > 400 kV or not applicabile at all.
No
Group
Southern Company
Wayne Johnson
Yes
The currently drafted standard does not include GOPs as an applicable entity. Consideration should be made to include them as an entity for reliability purposes. For example, a GOP may decide to take a unit offline if a K7 is declared, and if so, the reliability entities would need to know that these units are not available, if needed. In addition, if GOPs are added as applicable entities, they need to have a requirement to provide their plan to the reliability entities. Although we are suggesting adding the Generator Operator as an applicable entity, we do suggest that they be allowed to develop their own GMD Operating Plan or implement the GMD Operating Plan of its Transmission Operator. We also believe, consistent with our response to Question #7 below, that the standard should not apply to BAs, as the the risks mitigated by requiring them to have Operating Procedures are things that the TOP monitors and can either take action themselves or instruct the BA to redispatch generation.
Yes
The SDT should consider creating criteria for the RC to use to ensure plans are coordinated and compatible. For example, criteria were developed for RCs to use to approve TOP restoration plans in EOP-006-2, R5, which indicates that the “Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its Reliability Coordinator Area.” Similarly, the SDT or a committee designated by the SDT should create criteria for RCs to use to ensure plans are coordinated and compatible.
Yes
An additional requirement should be added requiring BA/TOPs to send their initial plans and any revisions to the RC for review, since the RC has responsibility for ensuring plans are coordinated and compatible.
Yes
For R3.1, to address potential confidential data issues, the weather data utilized should be publicly available . We recommend changing R3.1 as follows: R3.1 The steps or tasks for the acquisition and dissemination of publicly available space weather information to its System Operators.
Yes
Yes
As stated above in our response to Question #1, we suggest that the BA should not be required to have Operating Procedures for GMD. The risks mitigated are things that the TOP monitor and can either take action themselves or instruct the BA to redispatch generation.
No
No, as long as the phase 2 standards are non-prescriptive. EOP-010-1 allows entities to account for regional differences that exist in their area through the development of their plans. This methodology of accounting for regional differences through plan development needs to be continued as the phase 2 standards or standard changes are developed.
No
Group
Emprimus LLC and Volkmann Consulting
Terry Volkmann
Yes
For the Stage 1 standard, appropriate inclusion of affected transformers is not as important as it will be in Stage 2. What is important for the Stage 1 standard to capture in its applicability section the portion of the BES most effected by a GMD and

the most influential to maintain BES reliability. In capturing RC, BA and TOP with 200kv transformers, the SDT has captured entities that have influence over the 200kv and above system. For entities the own and operate facilities between 100 and 200kv, their system reliability will be maintained by the RC and any neighboring / over-arching entities that operation 200kv and above.
No
We agree with the language of develop, maintain and implement a GMD Operating Plan. However, the requirement does not have any evaluation of whether the Operating Plan was appropriately and effectively implemented for an event. M1 should include a post-event evaluation activity and subsequent documentation of the plan implementation.
No
We agree with the language stated in R3. However, R3 should include the requirement of the TOP to communicate that they have implemented their Operating Procedures. Likewise the requirement does not have any evaluation of whether the Operating Procedures were appropriately and effectively implemented for an event. M3 should include a post-event evaluation activity and subsequent documentation of the plan implementation
Yes
R5 should be applicable to RC also.
Yes
Yes
No
Yes
GIC mitigation systems should be excluded from the SPS definition.
Group
FirstEnergy
Doug Hohlbaugh
Yes
Yes
Yes
No
Requirements R2 & R4 FirstEnergy questions the need for Requirement R2 and R4 which propose an every 3-year review of GMD operating procedures. This is an administrative task and should not be a reliability requirement subject to mandatory enforcement. The requirements do not adhere to principles identified by the Par. 81 team and now being applied across all drafting teams. Par 81 Criteria B1 Administrative which states "The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome." Additionally, an upcoming draft revision to the NUC-001 standard is proposing to remove a similar obligation in NUC-001 (R9.1.3). FERC’s Order 779 did not suggest a need for the responsible entities to periodically update their GMD Operating Procedures every 3-years. Rather in paragraph 39 the Commission states "While responsible entities will develop and implement operational procedures, NERC can support their efforts, for example, by identifying and sharing operational procedures found to be the most effective. NERC should also periodically survey the responsible entities’ operational procedures, offer recommendations based on lessons-learned and new research findings, and re-evaluate whether modification to the Reliability Standards is warranted." It is our understanding that it’s the ERO’s responsibility to reconsider whether or not more specific minimum GMD procedure expectations should be codified in the standard at some future date. This could be done for example during the 5-year review period of the standard and the NERC GMD Task Force could be tasked with providing the review required of NERC and propose changes to the GMD standard if needed. Requirements R5 Requirement R5 indicates a need for the Operating Procedures to be located at the primary and back-up control center facility. The intent of Requirement R5 is already covered in standard EOP-008-1, R2. FirstEnergy recommends that Requirement R5 be struck as a redundant obligation.
The comments are supported by the following GMD standard ballot body members representing FirstEnergy: Bill Smith, Segment 1 Transmission Owners; Cindy Stewart, Segment 3 Load Serving Entities; Doug Hohlbaugh, Segment 4 Transmission Dependent Utilities; Ken Dresner, Segment 5 Electric Generators and Kevin Querry, Segment 6 Brokers, Aggregators, and Marketers.

Yes
Yes
No
No
Individual
David Jendras
Ameren
We believe GMD is a regional issue and therefore a NERC Standard is not necessary. We believe that studies need to be completed before considering a new NERC Standard. In addition, an entity cannot develop operating plans and procedures based on unstudied GMD conditions. After the initial assessments of potential impacts of GMD on BES reliability is complete, then appropriate (if necessary) plans and procedures can then be developed and if necessary a standard could then be drafted based on results of the studies.
No
We believe that the scope should include initial assessments of potential impacts of GMD before a standard is drafted.
Individual
Catherine Wesley
PJM Interconnection, L.L.C.
Yes
PJM has also signed onto SERC's comments.
Yes
PJM has also signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments. PJM also signs onto the SRC's response to Question #3.
Yes
PJM has signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments.
No
PJM has signed onto SERC's comments.
No
PJM has signed onto SERC's comments.
Individual
Michael Lowman
Duke Energy

Yes
While Duke Energy agrees in principle with starting at 200kV and above for having a GMD process/procedure, we believe that 300kV and above would be a more appropriate bright-line. In addition, if the bright-line remains at 200kV and above, we recommend the SDT should consider an alternative method of including only 200kV and above BES elements. Lastly, Duke Energy believes that only transformers with wye connected winding(s) should be included because only wye connected winding(s) are affected by GIC(s).
Yes
Duke Energy believes R1.2 should be changed to “Each Reliability Coordinator shall have an Operating Process to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities in the Reliability Coordinator Area are coordinated and compatible.“
Yes
Yes
Duke Energy believes that “Same Day Operations” is a more appropriate time horizon for R1 and R3.
Yes
Yes
Yes
Duke Energy believes that due to regional variances, GMD procedures should vary based on GMD severity levels and kV thresholds.
Yes
If a TOP’s GMD procedure includes the curtailment of transactions to mitigate a potential GMD event, then the modification of a TOP(s)/TSP(s) business practices may be required.
Group
PacifiCorp
Ryan Millard
No
Generator Operators are listed as applicable functions within the SAR but are absent from the scope of applicability of EOP-010-1. If Generator Operators are not included under the standard they should be removed from the scope of the SAR, as this creates inherent confusion as to their explicit applicability to the standard. Additionally, PacifiCorp does not support inclusion of the BA as an applicable functional entity.
No
PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 2. R1.2 requires the RC to "determine" that the plans of the BAs and TOPs are coordinated but it is not clear what happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? PacifiCorp supports FMPA’s suggestion to look at the EOP-006 and EOP-005 construct for guidance.
No
PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 3. As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority to require that additional unit commitment or redispatch.
No
PacifiCorp affirms that if the intent of a review of an entity’s GMD plans and procedures is to improve the scientific understanding of GMDs, a more prudent requirement would be a periodicity that is post-operative event based.In the absence of a GMD event, the 36-month requirement is arbitrary and one that would likely be performed by an entity as a best business practice.
No
PacifiCorp believes the use of the term “Bulk Power System” confuses the scope of the standard. PacifiCorp recommends replacing “Bulk Power System” with the term “Bulk Electric System” and adding the caveate that the voltage limitation be set at 200kv and above.

No
Please refer to the answer supplied for Question 1.
No
None other than those identified.
Group
Beaches Energy Services
Steve Lancaster
Agree
FMPA
Group
Bureau of Reclamation
Erika Doot
Yes
No
The Bureau of Reclamation (Reclamation) and Western Area Power Administration (WAPA) recommend that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
No
WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation suggest that it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2 respectively. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address “The steps or tasks for receiving and disseminating space weather information to its System Operators.”
Yes
WAPA and Reclamation also believe that Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
Yes
Individual
Michael Brytowski
Great River Energy
No
GRE agrees with ACES recommending the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV. GRE agrees with ACES and does not believe that the

Balancing Authority (BA) should be listed as an applicable entity in the GMD standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. It would be the TOP or RC that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
No
GRE agrees with the MRO NSRF on the suggested language change in M1 for clarity and also to replace "implemented" with "coordinated". M1 should read: M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an "event driven" measure but the Requirement is to "coordinate" GMD Operating Plans. By using "coordinate" (versus implement) within the Measure, the measure uses the same words as the Requirement. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
Yes
Because of the wide-area nature of a GMD event, GRE is suggesting a higher level authority such as the NERC Operating Committee or a NERC technical committee consider drafting guidelines to provide details in preparing for GMD events that would include recommendations to entites in areas susceptible to GMD events.
No
With NERC's Relaibilibity Assurance Initiative (RAI), the P81 initiative and the work performed by the Independent Expert Review Project, R2 & R4 are administrative in nature and suggest the drafting team remove these two requirements. Similarly, R5 is also in administrative and is redundant with R3 because R3 has an implementation requirement. Per the P81 NOPR, CIP-003-3, R4 which required the cyber security policy be available to all personnel with CCA responsibilities, has been approved to be retired.
GRE agrees with ACES, The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions". A operating plan contains operating procedures and processes.
Yes
No
As previously stated in Q1, the Balancing Authority (BA) should not be included in the standard.
Yes
See ACES Comment for question 8.
No
The drafting team needs to consider the impacts to smaller entites. Smaller entities have limited resources especially when considering hardening transformers against GMD events. A cost benefit analysis should be considered when weighing the reliability gains versus the costs of hardening the electric system.
GMD events cover a wide area and multiple entities. Planning Coordinators (PC) are the ones that should be conducting the initial assessments with recommendations to the individual entities. The scope of these studies are much broader than individual entites.
Individual
Wryan Feil
Northeast Utilities
Yes
I agree with the applicability, however if the definition of BES changes I do not think this standard should apply down to those with transformers having high sides of 100 kV. The impact of GMDs and the magnitude of GICs is greatly reduced at these lower voltages and doesn't warrant the additional burden it would impose.
Yes
I agree that the RC should coordinate the plans for the BAs and TOPs in its area. It might be beneficial that there be coordination at the RRO level so that RC plans are coordinated as well, since GMDs/ GICs do not recognize arbitrary system borders.
Yes
The language in R3 is adequate.

Yes
Comments on the Geomagnetic Disturbance Operating Procedure Template: Transmission Operator: Information and Indications: Triggers: External: Watch, Warning and Alert K index numbers are too low. K-index is known to be an unreliable predictor of GMD severity, however it makes no sense to activate procedures below K7. Triggers Internal: System-wide/ equipment-level: Parameters mentioned could be abnormal due to other causes. There should be corroborating evidence cause is GMD before entering procedure. Actions Available to the Operator: Should specify that the actions are not limited to those listed. Long lead-time: Safe system posturing (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study. Remove shunt reactors: some systems auto switch reactors. These (and capacitors) should be left in auto so that they can respond to voltage swings. Day-of-event: Increase situational awareness: These require being able to corellate the observed parameters to equipment/ system effect before taking actions Prepare for unplanned capacitor bank/SVC/HVDC tripping: Should add that multiple installations should be evaluated as a single contingency. Real-time actions: Safe system posturing (only if supported by study): Selective load shedding: No guidance is provided as to how this could help in a GMD. Manually start fans/pumps on selected transformers: Due to the hazard of potential catastrophic failure from static electrification caused when oil temperature is below 50 C, this section should not be mentioned. System reconfiguration (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study. Return to normal operation: Why is any time limit mentioned at all?
Yes
SAR scope is adequate.
No
I believe that due to the wide geographical impact of GMDs/ GICs the RRO should coordinate plans between their RCs and perhaps with other RROs.
No
All regional variances should be due to geographical, geological and system design factors and should be covered by developing earth and system models.
Yes
This project will require the conducting of detailed equipment analyses, and in the longer term regional earth conductivity and system modelling in order to determine impact of GMD/ GIC on equipment and systems. Monitoring and Indications Key parameters must be identified for control center monitoring (GIC, reactive reserves, harmonics, MVAR, etc.) and SCADA displays will have to be designed for operator use . Currently a project is underway to install GIC monitoring on selected transformers and to track the magnitude of GIC/ harmonics with GMD incidence (via Kp provided by SWPC). The impact on equipment of deviation from normal of these indications must be known, as well as actions recommended by the transmission owner. Once this is provided, the displays mentioned above can be designed. Procedure Development Once displays are developed as discussed above, a procedure will need to be developed to address requirements of EOP-010-1 R3. Currently in New England only the northern LCCs and ISO-NE have GMD procedures. These are of a general nature and may not be sufficient, but they will serve as a starting point for drafting operating procedures. (This presupposes that parameters for System Operator monitoring have been identified, provided to the control room, displays developed and the importance of the readings determined by the Transmission Owner.) The standard requires the RC to coordinate TOP procedures. This may result in a process similar to that for coordinating system restoration plans. Training Once a new procedure is developed and displays are created, a task analysis will need to take place to identify required changes to the company specific Reliability Related Task list and required modifications to the training program.This will involve development and delivery of additional classroom training and evaluation instruments, development and administering of Job Performance Measures for newly identified Reliability Related Tasks and development, delivery and evaluation of crew simulator scenarios.
1.) Training requirements should be added to PER-005. Any required training should be added to the applicable GMD standard(s) (e.g. EOP-010-1.) 2.) The requirement to have the stage 2 standard done and in effect within 18 months is reasonable, however there should be adequate time within the resulting standard for entities to conduct the required earth/ system studies and alalyze them. Adequate time is also important due to the need to coordinate mitigation efforts across areas to ensure other entities are not adversely impacted by your organizations actions.
Individual
Phil Anderson
Idaho Power Company
No
For stage 1, operational procedures make sense for Transmission Operations and not necessarily for Generation Operations. However, generator step-up transformers (GSUs) with a grounded wye high side can be affected by geomagnetic induced current (GIC). If the GSU is the property of and/or controlled by a generator operator, transformer information such as GIC, temperature, dissolved gas and abnormal operation may not be easily monitored by the

Transmission Operator. Any operational changes made by the Generator Operator will need to be coordinated by the Transmission Operator but the Transmission Operator may not be aware of GSU status. While System wide GMD operating procedures do not apply to Generator Operators, equipment level situational awareness and monitoring might. Idaho Power believes this standard should also apply to Generator Operators. Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities Section 4.
Yes
Yes
Agree in General. Propose adding Generator Operator to R3 and M3. The Reliability Coordinator needs to coordinate their procedures with the Transmission Operator, Balancing Authority and Generator Operator.
Yes
Agree in General. Propose adding Generator Operator to R4, M4, R5 and M5. Many of the other standards are using a five year review cycle. The review requirement should also include a trigger based on system upgrades or major changes to system topology.
No
Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities.
Group
Puget Sound Energy
Denise Lietz
No
The drafting team should ensure that the voltage level in the applicability statement does not include elements excluded by the Bulk Electric System definition. Specifically, it appears that the applicability statement would include equipment excluded from the BES by the language of BES Definition Inclusion I1 ("Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher..."). Also, voltage level is not the only measure of GMD influence on the BES - there are other factors that the standard should include in its assessment of applicability, including grounding method, grounding resistivity, core type and transformer (coiled equipment) connections. Leaving these factors out of the applicability section means that many entities who are unlikely to be affected by a GMD event will be unnecessarily burdened with drafting procedures that they may never need. In addition, it is not clear why the Balancing Authority is included as an applicable entity - in general, the actions available to the operators are transmission system specific. However, if the Balancing Authority is removed as a responsible entity, the drafting team should ensure that generation interconnection facilities are also assessed for applicability with respect to the interconnected TOP.
No
This requirement imposes a heavy burden on the RC. Understanding that some level of coordination is required, perhaps a lesser level of coordination will be acceptable, at least until phase 2 of the project is complete. Such coordination could be modeled after the approach in IRO-010, where the RC would set the specifications for the TOP Operating Plans and the TOP would be required to comply with those specifications.
Group
ACES Standards Collaborators
Jason Marshall
No
(1) We recommend the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the

drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV. (2) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extremen GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southern most entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies. (3) Given the unsettled GMD science, we think it is premature to write a standard requiring specific GMD operating plans and procedures and may cause considerable overlap and redundancy within the standards which the P81 project was intended to remove and which FERC has already proposed to approve. For example, TOP-001-1a R2 and R8 already requires the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Finally, EOP-001-2 R2.2 requires the TOP to “develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system”. These standards requirements are applicable at all times including during GMD events. Thus, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements. (4) The Balancing Authority (BA) should not be listed as an applicable entity in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. The background section is focused on preventing transformer hot spot heating and voltage collapse through excessive use of reactive power which clearly aligns with the TOP tasks and not the BA tasks in the NERC functional model. While the BA might have a role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support. The BA would commit generation in response to the TOP directions and would utilize existing operating procedures and processes it has for managing commitment of units. Its existing procedures and processes, for example, might include a minimum generation procedure. Implementing the procedure in response to excess generation that needs to be committed to respond to a GOP event would be no different than responding when load has simply decreased below the normal minimum generation limits. Thus, there is no need to add the BA because its existing procedures and processes would be sufficient to respond to the TOP actions.
No
(1) Having another duplicative “operating plan” does not improve reliability on the bulk electric system. The reliability standards already require several types of plans that could be enhanced to address GMD events. While we agree that flexibility is better than specificity, we disagree with the approach that another plan is required. The drafting team should consider enhancing existing operating plans and other approaches to respond to the FERC directive. (2) We believe that NERC should respond to the FERC directive with an equally efficient and effective alternative to developing a new reliability standard. Since the new standard will be largely redundant with with existing standards requirements, there is technical justification to support an alternate approach. The alternate approach would include relying on existing standards requirements. For example, IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective. (3) A reliability standard is not always the best solution to address a reliability concern. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. We cannot support a standard that attempts to address the issue in broad generalities. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
No
(1) The proposed standard is responsive to the FERC directive, but it fails to take into account existing reliability standards that overlap with the proposed draft, and creates duplicative requirements that could result in double jeopardy. For instance, TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Since the electric industry has always taken an “all hazards” approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. These policies and procedures would, therefore, be sufficient to respond to a GMD event without the need to make them specific to the GMD event or without the need to create a duplicative standard. The drafting team or a NERC technical committee, such as the Operating Committee, could draft a reliability guideline to provide additional detail of how to prepare for GMD events and make recommendations for utilities in areas susceptible to GMD events to include preparations in their planning processes.
No
(1) Requirements R2, R4 and R5 meet one or more Paragraph 81 criteria and should not be written as separate

requirements that will result in a separate violation for failing to conduct the review on a timely basis or failing to have a copy of the operating plan or procedure in the control centers. A requirement is subject to retirement under P81 if the requirement fits any of the following criteria: it is administrative in nature, requires data collection/data retention, purely documentation or reporting, requires periodic updates, concerns only a commercial or business practice, is redundant with other standards, hinders the protection or reliable operation of the BES, or has little, if any, value as a reliability requirement. (2) Requirement R5 is very similar to CIP-003-3 R4 which requires the cyber security policy to be available to all personnel with access to or responsibility for Critical Cyber Assets. In the P81 NOPR, FERC recently proposed to approve retiring CIP-003-3 R4 because it is administrative and it would be not be practical to implement the cyber security policy if it was not available to personnel. Similarly, R5 would be redundant with R3 because R3 has an implementation requirement. How can the TOP or BA implement the operating procedure if it is not available to its operating personnel per R5? How would an auditor verifying that a copy of the plan in the primary and backup control rooms benefit reliability? It could be placed in these rooms with no notification to system operators and no training provided to system operators on the implementation. Obviously, this would not support reliability. Requirements R2 and R4 are similar to the NUC-001-2 R9.13 which compel the Nuclear Plant Generator Operator and Transmission Entity to review their agreement every three years. FERC also proposed to retire it. Thus, R2 and R4 should be removed. If some vestige R2 and R4 are to remain, they should be made a sub-part of R1 and R3 so that a separate violation is not recorded for failure to review in the 36 month time frame. (3) We do agree that the 36-month time frame for review is reasonable.
(1) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will be viewed as this coordination. (2) The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on “Real-time conditions”. A operating plan contains operating procedures and processes. (3) Part 3.1 in R3 is unnecessary because NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. There is not a need to codify a process that is already in place and works effectively.
Yes
While we agree that the SAR does provide a plan to address the FERC directives, we continue to believe new standards with requirements to write specific operating plans or procedures is premature and that NERC should pursue and equally effective and efficient alternative. The electric industry is already required to have policies and procedures to manage emergency conditions through the requirements such as TOP-004-2 R6.1 and EOP-001-2 R2.2. Since the electric industry has always taken an “all hazards” approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. The electric industry’s excellent response to large events such as hurricanes, blizzards, and tornadoes has proven the “all hazards” approach to planning is effective.
No
As stated above in question one, the Balancing Authority (BA) should not be included in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. While the BA might have role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
Yes
(1) Because the science it unsettled at this point, it is difficult to imagine a situation with a GMD event so severe that it impacts significantly the furthest southern parts of the U.S. Thus, a regional variance is likely necessary for these areas. However, until the science is settled it is challenging to know where to draw the line for where the regional variances are needed geographically or geologically.
Yes
This standard will impact multiple business practices within the industry regarding budgetary issues. The cost of hardening transformers to withstand severe GMD events does not justify the reliability gains. This is especially true for smaller entities with limited resources.
The SAR discusses additional training requirements that ultimately will impact system operators. System operators already have a heavy training load from mandatory training required to meet the PER requirements (i.e. 32 hours of emergency operations training) to the training requirements to maintain NERC certification (i.e. 200 hours every three years for an RC).

We would advise the drafting team to be careful to not overburden the system operators with additional training requirements that could distract them from doing their job of maintaining system reliability.
Group
DTE Electric
Kathleen Black
No
System study of areas potentially affected by GMDs should be identified before standard is written requiring all entities to have plans and operating procedures.
No
Instead of each RC, TO and BA developing its own plan to mitigate effects of GMDs, the standard should state that each TO and BA have a plan to support its RC's GMD plan. If individually created, the plans may conflict.
No
Entities with no previous effects from GMDs should be exempted by their RX from developing a plan and entities with potential problems with GMDs should be required to develop plans to support their RC's plan and provide plan details to their RC.
No
Please see previous comments from Questions 1, 2, and 3.
Yes
Yes
No
No
Individual
Patricia Metro
National Rural Electric Cooperative Association (NRECA)
No
NRECA recommends increasing the voltage level threshold from 200 kV to 345 kV. The drafting team has not provided a technical justification for choosing the 200 kV threshold. It appears that from the limited previous experiences associated with GMD events that there was no substantive impact on equipment at voltages below 345 kV. In addition, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast. The inclusion of the Balancing Authority as an applicable entity is not necessary. If the events being addressed in this standard are solely related to preventing transformer hot spot heating and voltage collapse through excessive use of reactive power, these types of events are managed by the Transmission Operator not the Balancing Authority. The Balancing Authority will only provide generation support as directed by the Transmission Operator.
No
As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
NRECA agrees that the 36-month time frame for review is reasonable.
NRECA is does not believe that it is necessary to develop a separate GMD standard to address requiring Operating Procedures for GMD events. Criteria for addressing such events can easily be added to existing standards that require entities to have Operating Procedures. Suggesting a new standard that has similar requirements as existing standards does not adhere to the spirit of the P81 initiative to eliminate unnecessary duplicative requirements. Examples of requirements that could be revised to address GMD events are: IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other Reliability Coordinators. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. R5 - NRECA agrees that it is reasonable to require that a copy of an applicable entity’s GMD Operating Procedures is in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its

implementation date. In the Time Horizon designation for the requirements of this standard, the “Long Term Planning” horizon should be removed. As written, this standard addresses Operating Procedures to address Real-time events not those that meet the criteria for a “Long Term” event.
Yes
NRECA agrees that the SAR as drafted provides a scope to address the directives in Order No 779, but believes as explained in response to Question 5 the directives could be addressed by modifying existing standards as an alternative to developing a new standard.
No
As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
Yes
As explained in response to Question 1, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast.
Group
SPP Standards Review Group
Robert Rhodes
No
Please refer to our comment in Question 7 directed toward applicability in the SAR.
Yes
While we concur that R1 addresses the FERC directive, we have some reservations with the use of the word ‘coordinated’ in R1.2 especially along the lines of what specifically will be required by the responsible entities to show coordination. Hopefully, the Reliability Coordinator will provide those details in his processes. Additionally, we would encourage the NERC Operating Reliability Subcommittee to ensure consistency in the processes used by the Reliability Coordinators throughout NERC.
Yes
No
To address timing issues in R5, we suggest inserting the word ‘current’ between the ‘a’ and ‘copy’ and deleting the phrase ‘so that it is available to its operating personnel prior to its implementation date’. R1 would then read Each Transmission Operator shall have a current copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms. For consistency with EOP-005, we would suggest that the VRF for R5 be reduced to Low. This is an administrative requirement and does not merit a Medium VRF. Additionally, we wonder why the Reliability Coordinator is not required to have a copy of its GMD Operating Plan in its primary and backup control centers.
Delete the phrase ‘and submit(ted) them for approval’ from the VSLs in R4. R4 does not require approval.
Yes
The SAR, as well as the draft standard, refer to the BPS. Given the restrictions as proposed in the standard on transformers with high-side terminals of 200 kV and above, wouldn’t the reference be more appropriate to the BES?
No
The Functional Model does not assign transformer operation to the Balancing Authority yet the drafting team makes a connection between transformers and the Balancing Authority by incorporating the Balancing Authority in the Applicability Section. Why did the drafting team make this decision? Shouldn’t the Balancing Authority be removed from the Applicability Section since it is concerned with balancing generation to load and not operating transformers? The Balancing Authority already has procedures to assist it whenever load or generation within its Balancing Authority Area is lost. It’s reason for the loss is immaterial to the Balancing Authority, the procedures it has to cover this situation would be similar regardless of the cause. In any event, the Balancing Authority has no responsibility to mitigate issues associated with a transformer within its Balancing Authority Area. That functionality resides with the Transmission Operator.
No
While we are concerned with the intent of continent-wide requirements, if accomplished as proposed by the drafting team with flexibility provided for responsible entities to tailor their response to both stages of standard development to their risk and exposure based on their geography, geology and system topology, then regional variances may not be needed. Otherwise, regional waivers or exemptions may be appropriate.
Yes
We foresee the need for a study/modeling group similar to the MWG which would assemble the appropriate data base upon

which collaborated studies, similar to the interregional transfer capability studies being done today, would be conducted. The results of those studies would then also be made available to any responsible entity for purposes of GMD assessment.
Individual
Bill Fowler
City of Tallahassee
No
R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC. The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
Individual
Scott Langston
City of Tallahassee
No
R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC. The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
Group
Bonneville Power Administration
Jamison Dye
Yes
Yes
BPA’s position is that the primary entities responding to GMD events are the TOPs and BAs. BPA believes the RC should be required to develop the criterion for their Operating Plan in direct coordination with the TOPs and BAs in their area in

order to avoid the RC developing a plan that may not be compatible with the region. Additionally, the RC should be the primary source of space/weather information and be required to disseminate that information to the TOPs and BAs in their area.
Yes
Yes
BPA agrees that operational procedures should be put in place but they will not have sufficient analysis of the full impact of certain actions due to certain technologies not being available at this point. Specifically, the reactive and thermal impacts of GMD on transformers.
Yes
Yes
No
No
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOPs and BAs” with “applicable TOPs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC. The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. This reference is valuable to entity wishing to make an informed vote.
Individual
Bret Galbraith
Seminole Electric
No
Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of various entity specific characteristics in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures: “An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures.” Seminole believes that this is not clear in the Requirement and wishes that the NERC SDT specifically state the ability for an entity to tailor their plans and/or procedures to their environment. In addition, the suggested language is pulled from the SAR for this project.

Group
Colorado Springs Utilities
Kaleb Brimhall
No
• GOP should also be included. • Voltage level not a good indicator of susceptibility to ground induced currents. Possibly latitude, transmission line orientation or transmission line length a better indicator. If voltage were to be used, think higher voltage should be considered.
Yes
Yes
Yes
Comments on Requirement 1: • In need to include a requirement for the RC to acquire and disseminate space weather information to the applicable entities within their footprint. Comments on Requirement 3: • From the glossary; Operating Procedure (in part): "The steps in an Operating Procedure should be followed in the order in which they are presented"; Operating Process (in part): "An Operating Process includes steps with options that may be selected depending upon Real-time conditions." The language in the Standard will be what is audited to, notwithstanding what any individual utility may titles their documents. The actions which may be required during a GMD event are far better presented in an Operating Process (as defined) than an Operating Procedure (as defined). There is no way that a TOP could follow the exact same step-by-step procedure for all GMD eventualities, but that is what the "Operating Procedure" term demands. Comments on Requirement R3.1: • Need to eliminate the requirement to acquire space weather information in R3.1, and have it a part of the information that the RC would disseminate to ensure consistency and coordination from the RC. Comments on Implementation Plan: 1. Need to ensure that RC develops and disseminates their plan 1st with time included to incorporate RC plan into BA/TOP/GOP plans. 2. Implementation period needs to be extended from 6 months to 12 months.
Abstained from Commenting.
Yes
Yes
1. Variances are absolutely going to be necessary based on geography, geology, and system topology.
Abstained from commenting.
None
Group
JEA
Tom McElhinney
No
The applicable entities should't not include the BA but needs to include the GOs. Generator step up transformers are more critical to BES reliability than substation step down transformers. Only BES transformers should be included.
No
A vulnerability study is required before good operating procedures can be developed
No
BA should be removed
Yes
Yes

Yes
No
Individual
David Gordon
Massachusetts Municipal Wholesale Electric Company
Agree
American Public Power Association (APPA)
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Group
Santee Cooper
S. Tom Abrams
Yes
Recommend the SDT consider changing he high side terminal voltage on transformers to greater than 300 kV. The focus of the standard should be at higher voltages where the line length makes the lines more vulnerable to geomagnetically-induced currents.
Individual
Bryan Griess
Transmission Agency of Northern California
TANC appreciates the performance flexibility that has been built into the current draft of this standard, but has concerns regarding the approximately six month implementation period between its approval and effective date. Of particular concern is the ability for each Reliability Coordinator to ensure coordination and compatibility between its GMD Operating Plan and the GMD Operating Procedures for all Transmission Operators and Balancing Authorities in its footprint during such an abbreviated period. As this initiative moves forward, TANC requests that NERC continue to carefully consider the scope of entities and assets that will be subject to this and subsequent standards so that the costs borne by the industry are commensurate with the anticipated benefit to reliability.
Group

Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
NRECA SERC
Group
Foundation for Resilient Societies
William R. Harris
No
Standards relating to Operating Procedures should apply to high side Transformers of 100 kV or higher. Despite higher resistance, transformers in the 100 kV to 200 kV range contribute a significant proportion of GICs that can destabilize the grid. TJ Overbye et al (2012)estimate less than 60% of total MVAR is captured in New England and Michigan if transmission under 230 kV is excluded from protection. New transformers in the 100 kV to 200 kV range are projected by the Energy Information Administration at about 20% of all new EHV transmission mileage planned for the 2012-2018 period. NERC must include generating entities, because existing studies suffice to demonstrate both vulnerability of GSU transformers operated by Generating entities and need for equipment monitoring at generator stators, and related operating procedures to protect generators in severe geomagnetic storms. GSU Generators are at greater risk than generally recognized. See studies by Legro, Abi-Samra and Tesche at ORNL (1985); Walling & Kahn (1991); J G Kappenman, Storm Analysis Report R-112, section 8 (2011); and Luis Marti, "Generator Thermal Stress during a Geomagnetic Disturbance" (2013). Of critical importance, the President of the United States has existing legal authority to order the de-energizing of electric generating facilities that are oil or gas-fired if an emergency so requires. To utilize this authority upon confirmed space warning of a severe solar geomagnetic storm, it is essential that all generating entities serving the bulk power system be included in emergency operating procedure standards; their personnel be trained to validate and confirm de-energizing orders and procedures (and re-energizing procedures), with a multi-day strategic warning but only tens of minutes for tactical order, validation, and execution. Because most of the generating facilities serving the bulk power system are not now equipped with protective equipment that would enable these facilities to "operate through" a severe solar geomagnetic storm, it is essential that generating entities be included in the Operating Procedure coverage and standards. Further, the Nuclear Regulatory Commission has existing authority to order de-energizing and safe shutdown of the 102 NRC licensed nuclear power plants in the U.S. or a subset that are especially affected by a particular GMD event. Generating entities may need to review operating procedure options for rapid shutdown of generators if GSU transformers are not equipped with protective hardware. Beyond the practical necessity of including transformers and transmission equipment in the 100 kV to 200 kV range, FERC Order 779 applies to the entire bulk power system, which is now defined as commencing at 100 kV or above and not 200 kV or above. It would be illegal for NERC to exclude a significant proportion of the transmission line mileage (for many utilities more than half total EHV transmission mileage). Even if EHV transformers above 200 kV are later protected with neutral ground blocking equipment, leakage of GICs from lower voltage equipment will add significant Mvar into regional grids. FERC intended standards to protect the entire bulk power system of 100 kV or higher; NERC's participating entities should respect and support this federal policy.
Yes
No
Reason: Earlier comments on the Operating Procedure Templates submitted by the Foundation for Resilient Societies were ignored, and not addressed on their merits by the GMD Task Force management and by the NERC Planning Committee. See our previous comments at: https://resilientsocieties.org/images/Comments Operating Procedure Template NERC GMDTF Phase 2 Rev1.pdf.
Yes
The Foundation for Resilient Societies has concerns that the NERC Planning Application Guide, developed without full public access to the related model assumptions, will mis-characterize geomagnetic latitudes with geographic latitudes; and will result in scientifically invalid assumptions that the NERC modeled "operating procedures" will suffice without need for hardware protections. For our Foundation review of the Draft NERC GMD Planning Application Guide, our review dated August 9, 2013, see: http://resilientsocieties.org/images/Resilient_Societies_Comments_on_GMD_Planning_Application_Guide _Final.pdf.
Yes
Yes
Yes
Yes

For effective operating procedures implemented through regional balancing authorities, improved near-real-time GIC monitoring will be needed for all GSU transformers, SVC equipment, and major generating equipment at risk in severe solar storms. Regional balancing authorities will require improved near-real-time monitoring to prepare and protect ready reserves. Communications must be designed to operate even during severe solar storms. Regional balancing authorities will need to be in contact with the White House Situation Room and federal command centers elsewhere.
For concerns of the Foundation for Resilient Societies, see our website at www.resilientsocieties.org. A case study of Maine and ISO-New England utilizing recently revised operating procedures documents our concern that regional "ready reserves" in a severe geomagnetic storm are likely to be inadequate due to a combination of vulnerable long distance HVDC transmission lines, a record of SVC "trips" during only moderate solar storms, and unprotected generating equipment in New England, where high GICs are recorded.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
Yes
Yes
We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedures in place and be required to monitor GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT propose retiring R3 of IRO-005-3.1a. If R3 is to be retained, then it does not mention “applicable” BAs and TOPs, which it should.
No
Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operatinbg personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.
No
If the Stage II assessment is done from a wide-area perspective, how would it work from a functional entity perspective? Other than in the ERCOT interconnection, which functional entity would be responsible at the interconnection level? No relevant functional entity has an interconnection-wide geographic scope?
Yes
No
No
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
No
Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System” proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One – Assess and Baseline Risk Phase Two – Perform Technical and Programmatic Analysis Phase Three – Develop Integrated Solutions Phase Four – Implement Solutions and Adjust System Procedures It seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them

periodically as data improves. To this end NERC has developed the “Geomagnetic Disturbance Operating Procedure Template” for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs. Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >200kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
No
Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC’s, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events. Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
No
While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC’s technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Yes
Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
In general, we agree with R1 & R1.1. However, we feel that R1.2 should be modified. Instead, we recommend the requirement read something like this: [1.2 A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.]
No
Recommend revising R3.1. It isn’t clear as to what periodicity that an entity should be collecting and disseminating this information. Also, it is unclear as to what would qualify as a source to meet this requirement (i.e. is any ‘space weather’ source acceptable?). Suggest removing this requirement and indicate in prior requirement (R1) that RCs have the responsibility of collecting and sharing space weather information with TOPs and BAs, and RCs must subscribe to an authoritative space weather source.
Yes
The current IRO-005-3.1a R3 requires RCs to notify TOPs and BAs of certain GMD events. Consider deleting this requirement in IRO-005-3.1a as part of this implementation plan and add something in this standard (EOP-010) requiring RCs to make that notification. The pending approval of IRO-005-4 removed the explicit requirement, but development history indicates that it considers GMD to have an Adverse Reliability Impact that would require RC notification to entities.
Yes

Yes
Individual
Angela P Gaines
Portland General Electric Co
Agree
PGE supports WECC's position regarding the standard as it relates to the implementation timeframes.
Group
El Paso Electric Company
Pablo Onate
EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 yearlong implementation period instead.
Individual
Rhonda Bryant
El Paso Electric Company
EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 year long implementation period instead.
Individual
Joe Tarantino
Sacramento Municipal Utility District
No
~1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down transformers to distribution. ~2. Referring to the Oak Ridge national Laboratory 319 report, the winding(s) in question needs to be wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with "wye" connected winding(s) above a certain threshold voltage. Three phase core transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single core transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase core transformers.

No
No
Every 36 months is too short of a time-frame. It would be more appropriate to have a review of a potential plan, if indeed needed, when system configurations warrant a review. The review period should be set by the entity, IF there is even a concern.
SMUD also has concerns with the implementation period and questions whether or not six months is adequate time for the BA and TOP to develop the required GMD Operating Procedures and for the RC to develop the required Plan to coordinate those GMD Operating Procedures. SMUD also encourages the SDT to consider the GMD threshold application to be raised to 300+kV, and also encourages the Project 2013-03 Standard Drafting Team to consider the comments submitted by Florida Municipal Power Agency (FMPA) related to applicability of the standard.
No
SMUD is unaware of WECC any regional variance.
No
Individual
Laurie Williams
PNM Resources
Agree
WECC Staff
Individual
Nathan Mitchell
American Public Power Association
No
APPA appreciates the SDT's effort to limit the applicability of the proposed standard by setting a voltage threshold for TOPs and BAs. On the July 30th webinar the SDT stated that a technical whitepaper was being developed to justify the 200 kV threshold. APPA will hold any comments on the voltage threshold until after the whitepaper is released. We request that the whitepaper be provided soon so the industry has time to discuss this threshold prior to the final comment and ballot period. APPA recommends that the SDT modify the applicability section wording to replace "transformers" with "BES transformers." Including only BES transformers will make the applicability of the standard clear. Some Transmission Owners may have transformers with high side voltage above 200 kV, but they are connected radially so are not part of the BES. These transformers should be out of scope for this standard.
No
APPA suggests that the word "all" in Requirement R1.2, be replaced with the word "applicable." APPA believes using the word "all" in this context will bring into applicability TOs and BAs that have transformers below the 200 kV threshold. Replacing "all" with "applicable" will limit confusion and avoid conflict with the applicability section of the standard. APPA is also concerned with the words "coordinated and compatible" in R1.2. On the July 30th webinar the SDT stated that a full scale power flow analysis would be the ideal way for the RC to determine compatibility of various plans. APPA is concerned with the cost to TOs and BAs of meeting this "ideal" therefore we suggest that the SDT give guidance on acceptable alternatives.
Yes
Yes
Yes
Yes
No
No

Individual
Linda Jacobson-Quinn
Farmington Electric Utility System
Yes
No
Recommend rewording R1.2 ”A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.“ FEUS has concerns with how the RC would ensure ALL the TOP and BA plans are coordinated and compatible. In addition, FEUS is unclear what demonstrates a plan is compatible.
No
Recommend revising 3.2. to the following, “The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator to mitigate the effects on the system from GMD events.” FEUS agrees it is pertinent mitigating activities are coordinated; however, we believe this level or coordination should be in line with what is expected for coordination activities during a restoration.
Yes
FEUS appreciates the work by the SDT team to allow entities flexibility when developing their operating procedures for mitigating GMD. The flexibility allows for entities to develop the plan that works with their system
Yes
Yes
No
No
Individual
Rick Terrill
Luminant Generation
Yes
Yes
Yes
Yes
Luminant has voted Negative as the posting and balloting of the GMD proposed standard did not follow the NERC Rules of Procedure. Luminant appreciates the technical work of the Ad Hoc group but believes the standard should have been posted for comments only, instead of being posted for balloting.
Individual
Scott Berry
Indiana Municipal Power Agency
Agree

IMPA supports the comments submitted by Frank Gaffney from Florida Municipal Power Agency.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
No
LADWP is making a correction to Question 1 and therefore is resubmitting its comments from yesterday. Please take these comments and regard the ones from yesterday. ____ Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One – Assess and Baseline Risk Phase Two – Perform Technical and Programmatic Analysis Phase Three – Develop Integrated Solutions Phase Four – Implement Solutions and Adjust System Procedures It seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the "Geomagnetic Disturbance Operating Procedure Template" for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs. Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >20kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
No
Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events. Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
No
While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Yes
Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
LADWP does not currently have a response for this question.
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Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Monitoring

The Project 2013-03 Drafting Team thanks all commenters who submitted comments on the draft stage 1 Standard (EOP-010-1) and Standard Authorization Request (SAR) addressing stages 1 and 2. Project 2013-03 will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by GMD in two stages as directed in FERC Order No. 779:

1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures with predetermined and actionable steps to take prior to and during GMD events which take into account entity-specific factors that can impact the severity of GMD events in the local area.

2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. The Stage 2 standard(s) must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts. If the assessments identify potential impacts from benchmark GMD events, the standard(s) will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

The standard and SAR were posted for a 45-day formal comment period from June 27, 2013 through August 12, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 85 sets of responses, including comments from over 225 different people from approximately 140 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the project page.

Summary Consideration:

The drafting team has revised the standard to incorporate a number of stakeholder recommendations that the drafting team believes are appropriate to improve the standard. **As a result of comments received, the drafting team has identified the need to make significant changes to the standard. Although Section 4.12 of the NERC Standard Processes Manual indicates that the drafting team is not required to respond in writing to comments from the previous posting when it has identified the**

need to make significant changes to the standard, the drafting team is providing summary responses to the comments received in order to facilitate stakeholder understanding.

A summary response follows each question. Please note that because common issues were grouped together in the summaries, an individual's comment may have been addressed in the summary for a question that is different from the question in which they submitted the comment; the drafting team encourages reviewers to read all summary responses.

The drafting team made the following changes after reviewing stakeholder comments:

- A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in their Reliability Coordinator Area. IRO-005-3.1a Requirement R3 currently provides this obligation. However, the NERC Board has approved IRO-005-4 which would result in retirement of the requirement. The new Requirement R2 in EOP-010-1 will maintain the RC's responsibility for providing space weather forecast information. The implementation plan includes guidance for making the new Requirement R2 effective to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010-1 Requirement R2 are effective at the same time.
- In response to stakeholder comments that certain Requirements met Paragraph 81 criteria, administrative requirements for reviewing of GMD Operating Plans and Procedures within a 36-month period and for having a copy in the control room were removed.
- Several changes in language were made to improve the clarity of requirements and measures.
- Applicability:
    - Balancing Authorities (BA) have been removed from the applicable functional entities because there are no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The BA is not expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the Transmission Operator (TOP) and Reliability Coordinator (RC). Existing standards provide the required authority for action. A whitepaper with the drafting team's analysis is posted on the project page.
    - The applicable TOP has been clarified to include only those that operate power transformers with a high side wye-grounded winding with terminal voltage greater than 200 kV. This applicability statement describes the functional entity in terms of the assets that they operate, which could include non-BES assets. The applicability statement is not intended to define equipment to be protected by the Operating Procedures. The drafting team views 200 kV as the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. A whitepaper with the drafting team's analysis is posted on the project page.

Although some stakeholders suggested that Generator Operators (GOPs) be added to the standard as applicable entities, the drafting team maintains that a GOP's Operating Procedures specifically to mitigate the effects of GMD would need to be supported by an equipment-specific study and might require the use of GMD monitoring equipment. Because it is not reasonable to assume that all GOPs have such studies or monitoring equipment, GOPs have not been added to EOP-010-1. Consistent with Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03, and Generator Owners (GO) and GOPs will be considered for applicability with stage 2. A whitepaper with the drafting team's analysis supporting the applicability of EOP-010-1 is posted on the project page.

Some stakeholders also commented that the six-month implementation period was too short. The drafting team is sympathetic to the challenge of completing the necessary coordination in a six-month time period. However this implementation period was suggested in FERC Order No. 779 and the drafting team lacks strong justification for a specific longer period.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
3.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
4.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
5.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
6.	Joseph DePoorter	Madision Gas and Electric	MRO	3, 4, 5, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Marie Knox	Midcontinent Independent System Operator	MRO	2
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11. Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
12. Scott Nickels	Rochester Public Utilities	MRO	4
13. Terry Harbour	MidAmerican EnergyCompany	MRO	1, 3, 5, 6
14. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Lowman	Duke Energy	SERC	1, 3, 5, 6
2. Tom Pruitt	Duke Energy	SERC	1, 3, 5, 6
3. Andrew Witmeier	Midwest ISO	SERC	2
4. Terry Bilke	Midwest ISO	SERC	2
5. Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
6. Scott Walker	TVA	SERC	1, 3, 5, 6
7. Steve Corbin	SERC	SERC	10
8. Jeff Harrison	AECI	SERC	1, 3, 5, 6
9. Danny Dees	MEAG Power	SERC	1, 3, 5
10. Mike Bryson	PJM	SERC	2
11. Ray Phillips	AMEA	SERC	4
12. Tim Hattaway	PowerSouth	SERC	1, 5
13. Jim Case	Entergy	SERC	1, 3, 6
14. Patrick McGovern	Georgia Transmission	SERC	1
15. Scott Brame	NCEMCS	SERC	1, 3, 4, 5
16. Chris Wagner	Santee Cooper	SERC	1, 3, 5, 6
17. Greg McKinney	EKPC	SERC	1, 3, 5
18. William Berry	OMU	SERC	3
19. Sammy Roberts	Duke Energy	SERC	1, 3, 5, 6
20. Ben Deutsch	SERC	SERC	10

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Mark Godfrey	Pepco Holdings Inc	RFC	1, 3
2. Jane Verner	Pepco	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Sasa Maljukan	Hydro One Networks Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion	RFC	3, 5, 6
2.	Mike Garton	Dominion	NPCC	5, 6
3.	Randi Heise	Dominion	MRO	6
4.	Michael Crowley	Dominion	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL Energy Plus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Donald Weaver	New Brunswick System Operator	NPCC	2
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1
25.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
26.	Mark Kenny	Northeast Utilities	NPCC	1

9.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6
5.	Gary Kobet		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	OG&E	SPP	1
2.	Don Hargrove	OG&E	SPP	3
3.	Leo Staples	OG&E	SPP	5
4.	Jerry Nottnagel	OG&E	SPP	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Terry Volkmann	Emprimus LLC and Volkmann Consulting								X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gale Nordling	Emprimus	NA - Not Applicable	NA
2.	Fred Faxvog	Emprimus	NA - Not Applicable	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	RBB Vote - Seg 1	RFC	1
2.	Cindy Stewart	RBB Vote - Seg 3	RFC	3
3.	Doug Hohlbaugh	RBB Vote - Seg 4	RFC	4
4.	Ken Dresner	RBB Vote - Seg 5	RFC	5
5.	Kevin Querry	RBB Vote - Seg 6	RFC	6
6.	John Reed	FE	RFC	1
7.	Chris Pilch	FE	RFC	1
8.	Mike Miller	FE	RFC	1
9.	Marissa McLean	FE	RFC	1
10.	Larry Raczkowski	FE	RFC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Denise Lietz	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Erin Apperson	Puget Sound Energy	WECC	3
2.	Lynda Kupfer	Puget Sound Energy	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
3.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
4.	John Shaver	Southwest Transmission Cooperative	WECC	1
5.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	Paul Jackson	Buckeye Power	RFC	3, 4
8.	Bill Hutchision	Southern Illinois Power Cooperative	SERC	1
9.	Caleb Muckala	Western Farmers Electric Cooperative	SPP	1, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Daniel Herring	NERC Training & Standards Development	RFC	4
2.	Kent Kujala	NERC Compliance	RFC	3
3.	Al Eizans	Merchant Operations	RFC	5
4.	Barbara Holland	SOC	RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Michelle Corley	Cleco Power	SPP	1, 3, 5
3.	Louis Guidry	Cleco Power	SPP	1, 3, 5
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
6.	Beverly Laios	American Electric Power	SPP	1, 3, 5
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	James Nail	City of Independence, MO	SPP	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

9. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
10. Dennis Sauriol	American Electric Power	SPP	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Ran Xu	Technical Operations	WECC	1
2. Dan Goodrich	Technical Operations	WECC	1
3. James Burns	Technical Operations	WECC	1
4. Richard Becker	Substation Engineering	WECC	1
5. Don Watkins	System Operations	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Tom McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson	JEA	FRCC	1
2. Garry Baker	JEA	FRCC	5
3. John Babik	JEA	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20. Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Rene Free	Santee Cooper	SERC	1, 3, 5, 6
2. Chris Wagner	Santee Cooper	SERC	1, 3, 5, 6
3. Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21. Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22. Group	Pablo Onate	El Paso Electric Company	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
1. Gustavo Estrada	El Paso Electric Company	WECC 5										
2. Tracy Van Slyke	El Paso Electric Company	WECC 3										
3. Luis Rodriguez	El Paso Electric Company	WECC 6										
4. Pablo Onate	El Paso Electric Company	WECC 1										
23. Individual	Janet Smith, Regulatory Affairs Supervisor		X		X		X	X				
24. Individual	Bob Steiger		X		X		X	X				
25. Individual	Lloyd A. Linke		X									
26. Individual	Steve Rueckert											X
27. Individual	Wayne Johnson		X		X		X	X				
28. Individual	Ryan Millard		X		X		X	X				
29. Individual	Steve Lancaster		X		X	X			X	X	X	
30. Individual	Erika Doot		X				X					
31. Individual	Kaleb Brimhall		X		X		X	X				
32. Individual	William R. Harris									X		
33. Individual	Paul Rocha	CenterPoint Energy	X									
34. Individual	John Falsey	Invenergy LLC					X					
35. Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36. Individual	John Bee	Exelon and its Affiliates	X		X		X					
37. Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
38. Individual	Joe O'Brien for Ed Mackowicz	NIPSCO	X		X		X	X				
39. Individual	Steve Hill	Northern California Power Agency				X	X	X				
40. Individual	Melissa Kurtz	US Army Corps of Engineers					X					
41. Individual	Andrew Z. Pusztai	American Transmission Company	X									
42. Individual	Jonathan Appelbaum	The United Illuminating Company	X									
43. Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
44.	Individual	Anthony Jablonski	ReliabilityFirst										X
45.	Individual	Martyn Turner	LCRA Transmission Services Corp	X									
46.	Individual	Michiko Sell	Public Utility District No. 2 of Grant County, WA	X		X	X	X				X	
47.	Individual	Ben Li	Ben Li Associates		X								
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
49.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
50.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
51.	Individual	Jack Stamper	Clark Public Utilities	X									
52.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X				
53.	Individual	Rich Salgo	NV Energy	X		X		X					
54.	Individual	Jen Fiegel	Oncor Electric Delivery Complany LLC	X									
55.	Individual	Oliver Burke	Entergy Services, Inc.	X									
56.	Individual	Dan Inman	Minnkota Power Cooperative, INC.	X		X		X					
57.	Individual	Terry Baker	PRPA	X		X		X					
58.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
59.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
60.	Individual	David Jendras	Ameren	X		X		X	X				
61.	Individual	Catherine Wesley	PJM Interconnection, L.L.C.		X								
62.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
63.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
64.	Individual	Wryan Feil	Northeast Utilities	X									
65.	Individual	Phil Anderson	Idaho Power Company	X									
66.	Individual	Patricia Metro	National Rural Electric Cooperative Association (NRECA)	X		X	X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
67.	Individual	Bill Fowler	City of Tallahassee			X							
68.	Individual	Scott Langston	City of Tallahassee					X					
69.	Individual	Karen Webb	City of Tallahassee - Electric Utility										
70.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X				
71.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
72.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
73.	Individual	Bryan Griess	Transmission Agency of Northern California	X									
74.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
75.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
76.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
77.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
78.	Individual	Rhonda Bryant	El Paso Electric Company	X		X	X	X					
79.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
80.	Individual	Laurie Williams	PNM Resources	X		X		X	X				
81.	Individual	Nathan Mitchell	American Public Power Association			X	X						
82.	Individual	Linda Jacobson-Quinn	Farmington Electric Utility System			X							
83.	Individual	Rick Terrill	Luminant Generation					X					
84.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
85.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
Massachusetts Municipal Wholesale Electric Company	American Public Power Association (APPA)
Western Electricity Coordinating Council	Florida Municipal Power Agency
PRPA	Florida Power & Light
Beaches Energy Services	FMPA
Indiana Municipal Power Agency	IMPA supports the comments submitted by Frank Gaffney from Florida Municipal Power Agency.
US Army Corps of Engineers	MRO NSRF
Associated Electric Cooperative, Inc. - JRO00088	NRECASERC
Portland General Electric Co	PGE supports WECC's position regarding the standard as it relates to the implementation timeframes.
PPL NERC Registered Affiliates	SERC OC Review Group
Tennessee Valley Authority	SERC OC Review Group
South Carolina Electric and Gas	SERC OC Review Group

Organization	Supporting Comments of “Entity Name”
Clark Public Utilities	Snohomish County Public Utility District
Nebraska Public Power District	Southwest Power Pool (SPP)
PNM Resources	WECC Staff

1. **The SDT is proposing that the draft stage 1 Standard should apply to Reliability Coordinators, Balancing Authorities with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV, and Transmission Operator with a Transmission Operator Area that includes any transformer with high side terminal voltage greater than 200 kV. Do you agree that the SDT has correctly identified the applicable functional entities in the initial draft stage 1 Standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on the applicability section of EOP-010-1. All comments have been reviewed and the revised version of EOP-010-1 includes changes that the drafting team considers appropriate. The drafting team maintains that Generator Operators should not be an applicable entity in the Stage 1 standard and has removed the Balancing Authority from the applicability as well. All functional entities listed in the Reliability Functions section of the Standards Authorization Request may still be considered for applicability of Stage 2 standards. The drafting team has clarified that the applicable Transmission Operators are those with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV. The drafting team emphasizes that this applicability statement describes the functional entity in terms of the assets that they operate, and does not define equipment to be protected by the Operating Procedures. Additional technical details are available on the Project 2013-03 Project Page. A summary of comments and the drafting team's response is provided:

- **Applicability to Generator Operators. Commenters stated that that EOP-010-1 needed to include Generator Operators in order to require Generator Operators to develop procedures to protect or mitigate the effects of GMD on Generator Step-up transformers (GSUs).** To effectively assess the effects of GMD on a GSU and develop appropriate mitigating Operating Procedures, a Generator Owner and/or Generator Operator would require a GSU transformer study to determine the impact of Geomagnetically-induced Current (GIC) (GIC/thermal rating study) and equipment to monitor GIC at the high-voltage wye winding neutral. Requirements for studies and possible equipment for mitigation is beyond the scope for stage 1. Generator Owners and Generator Operators are appropriately included in the GMD Standards Authorization Request and will be considered for inclusion in Phase 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. The drafting team recognizes that some GO/GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure. Furthermore, The RC and TOP will be preparing a GMD Operating Plan and Operating Procedures respectively. Those procedures will address steps that each will be taking to address GMD impacts, which may include requiring one or more GOPs to take action. Existing standards provide obligations for the GOP to execute actions when requested by the TOP or RC (refer to TOP-001-2 and IRO-001-3), to prevent or mitigate identified emergencies. Additional technical justification for excluding GOPs and BAs from applicability in the stage 1 standard is provided in a supporting white paper posted on the project page.

- **Applicability to Balancing Authority. Commenters stated that the BA should be removed from applicability of the standard because the purpose and scope did not align with the BA functions in the NERC functional model.** The drafting team agrees with removing BAs from the applicability. BAs are responsible for the real time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the Transmission Operator (TOP) to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits. The BA would not be expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the TOP and RC. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and, at least, the concurrence of the TOP and/or RC. Additional technical justification for excluding GOPs and BAs from applicability in the stage 1 standard is provided in a supporting white paper posted on the project page.
- **Applicability to all networks greater than 200 kV with grounded-wye transformers. Commenters requested justification for this threshold, stated that the threshold was lower than necessary, or stated that the threshold was higher than should be allowed for reliability.** The drafting team has prepared a technical justification for establishing a 200 kV threshold in the applicability of EOP-010-1 and posted it to the project page. Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (for example 115 kV lines are typically less than 15 miles in average length), the resulting GIC generated by lines rated less than 200 kV are significantly less than those of higher voltages. Lines with voltage ratings less than 200 kV do not contribute a significant portion of GIC that result in half-cycle saturation of power transformers, and are typically ignored in system impact studies. Using a voltage higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap in many systems by excluding from the reliability standard a portion of the network that can be affected by GMD. Results of sensitivity analysis shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event. Therefore, establishing 200 kV as the lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature. Refer to the project page for a supporting white paper containing further analysis on this topic.
- **Relationship to the Bulk Electric System definition. Commenters wanted clarification about applicability to non-BES elements, or recommended language to specifically exclude non-BES elements.** The drafting team believes EOP-010-1 should apply to Reliability Coordinators and all Transmission Operators with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV. Regardless of BES definition, the >200 kV network can experience GMD impacts and needs to be included for the reliable operation of the Bulk-Power System as directed

in FERC Order No. 779. There is no requirement within EOP-010-1 for Transmission Operators to include or exclude specific transformers in their Operating Procedures.

- **Regional applicability. Commenters stated that entities in regions with lower risk or lacking historical evidence of GMD impacts should be excluded.** Stage 1 of FERC Order No. 779 is interpreted to apply to all regions. The proposed standard does not specify prescriptive measures and allows for each entity to consider entity-specific factors in developing their procedures or processes. Order No. 779 at P 29 directs NERC to "submit for approval one or more Reliability Standards that require *owners and operators of the Bulk-Power System* to develop and implement operational procedures to mitigate the effects of GMDs…" (emphasis added).

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) We recommend the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV.(2) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extremen GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southern most entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies. (3) Given the unsettled GMD science, we think it is premature to write a standard requiring specific GMD operating plans and procedures and may cause considerable overlap and redundancy within the standards which the P81 project was intended to remove and which FERC has already proposed to approve. For example, TOP-001-1a

Organization	Yes or No	Question 1 Comment
		R2 and R8 already requires the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Finally, EOP-001-2 R2.2 requires the TOP to "develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system". These standards requirements are applicable at all times including during GMD events. Thus, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements. (4) The Balancing Authority (BA) should not be listed as an applicable entity in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. The background section is focused on preventing transformer hot spot heating and voltage collapse through excessive use of reactive power which clearly aligns with the TOP tasks and not the BA tasks in the NERC functional model. While the BA might have a role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support. The BA would commit generation in response to the TOP directions and would utilize existing operating procedures and processes it has for managing commitment of units. Its existing procedures and processes, for example, might include a minimum generation procedure. Implementing the procedure in response to excess generation that needs to be committed to respond to a GOP event would be no different than responding when load has simply decreased below the normal minimum generation limits. Thus, there is no need to add the BA because its existing procedures and processes would be sufficient to respond to the TOP actions.
Sacramento Municipal Utility District	No	~1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down transformers to distribution.~2. Referring to the Oak Ridge national Laboratory 319 report, the winding(s) in question needs to be wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with "wye" connected winding(s) above a certain

Organization	Yes or No	Question 1 Comment
		threshold voltage. Three phase core transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single core transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase core transformers.
Colorado Springs Utilities	No	o GOP should also be included. o Voltage level not a good indicator of susceptibility to ground induced currents. Possibly latitude, transmission line orientation or transmission line length a better indicator. If voltage were to be used, think higher voltage should be considered.
American Public Power Association	No	APPA appreciates the SDT's effort to limit the applicability of the proposed standard by setting a voltage threshold for TOPs and BAs. On the July 30th webinar the SDT stated that a technical whitepaper was being developed to justify the 200 kV threshold. APPA will hold any comments on the voltage threshold until after the whitepaper is released. We request that the whitepaper be provided soon so the industry has time to discuss this threshold prior to the final comment and ballot period.APPA recommends that the SDT modify the applicability section wording to replace "transformers" with "BES transformers." Including only BES transformers will make the applicability of the standard clear. Some Transmission Owners may have transformers with high side voltage above 200 kV, but they are connected radially so are not part of the BES. These transformers should be out of scope for this standard.
Minnkota Power Cooperative, INC.	No	Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV and smaller, high impedance non-BES transformers serving load. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems.Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV and a base rating of at least XX MVA". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers. The addition of "XX MVA" will limit the inclusion of small 200+ kV connected transformers. It is unclear as to what that limit should be and the evidence for that limit is unknown. Alternatively, could make the statement "includes BES power transformers with a high side terminal voltage greater than 200 kV" but this could exclude large load serving

Organization	Yes or No	Question 1 Comment
		transformers that do have a significant effect in relation to GMD events.
MRO NERC Standards Review Forum (NSRF)	No	Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potential transformers with high side terminal voltage greater than 200 kV. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems.Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers.
Florida Municipal Power Agency	No	FMPA appreciates the efforts of the SDT and, in general, we believe the standard is good. However, we believe the Applicability of the standard needs improvement; and that is the primary reason we are voting Negative.The ORNL report, which FMPA believes is already unreasonably pessimistic, made several conclusions that are not reflected in the applicability that FMPA believes ought to be:1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down trasformers to distribution.2. The winding(s) in question needs to be grounded wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with grounded wye connected winding(s) above a certain threshold voltage3. According the the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers.4. The primary concerns for GIC is for voltage collapse or relay misoperation due to increased MVAR demand of transformers that could potentially result in cascading, and potential damage to transformers (see SAR description of Industry Need); hence, the applicability should not be to BAs but only RCs and TOPs (see additional discussion in response to question 3).5. FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. Almost all 230 kV transformers are 3 phase / 3 leg core transformers with a much lower probability of becoming saturated; whereas, according to ORNL, about 15% of 345 kV transformers are single phase transformers

Organization	Yes or No	Question 1 Comment
		(Figure 1-19). In addition, the resistance ot 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line.FMPA assumes that GSU's owned by the GO and operated by the GOP is intended to be included in the applicability (since the vast majority of GSU's are grounded wye connected on the high side), but under the interconnecting TOP's operating plan. However, the applicability does not reflect this. If the intent of the SDT is to include these GSUs, then the applicability ought to be changed accordingly. As such, FMPA suggests the following for applicability:4.1. Functional Entities:4.1.1 Reliability Coordinator4.1.3 Transmission Operator with a:4.1.3.1 Transmission Operator Area that includes any BES transformer with three single phase transformers connected in a grounded wye configuration of 300 kV or greater; or4.1.3.2 Transmission Operator Area that includes any BES transformer with at least one grounded wye connected winding greater than 400 kV (either three single phase transformers or a three phase transformer); or4.1.3.3 Transmission Operator Area that interconnects with any generator interconnection facilities that include a GSU that meets either criteria 4.1.3.1 or 4.1.3.2
Idaho Power Company	No	For stage 1, operational procedures make sense for Transmission Operations and not necessarily for Generation Operations. However, generator step-up transformers (GSUs) with a grounded wye high side can be affected by geomagnetic induced current (GIC). If the GSU is the property of and/or controlled by a generator operator, transformer information such as GIC, temperature, dissolved gas and abnormal operation may not be easily monitored by the Transmission Operator. Any operational changes made by the Generator Operator will need to be coordinated by the Transmission Operator but the Transmission Operator may not be aware of GSU status. While System wide GMD operating procedures do not apply to Generator Operators, equipment level situational awareness and monitoring might. Idaho Power believes this standard should also apply to Generator Operators. Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities Section 4.

Organization	Yes or No	Question 1 Comment
PacifiCorp	No	Generator Operators are listed as applicable functions within the SAR but are absent from the scope of applicability of EOP-010-1. If Generator Operators are not included under the standard they should be removed from the scope of the SAR, as this creates inherent confusion as to their explicit applicability to the standard. Additionally, PacifiCorp does not support inclusion of the BA as an applicable functional entity.
Great River Energy	No	GRE agrees with ACES recommending the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV.GRE agrees with ACES and does not believe that the Balancing Authority (BA) should be listed as an applicable entity in the GMD standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. It would be the TOP or RC that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
Los Angeles Department of Water and Power	No	LADWP is making a correction to Question 1 and therefore is resubmitting its comments from yesterday. Please take these comments and regard the ones from yesterday.____Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One - Assess and Baseline RiskPhase Two - Perform Technical and Programmatic AnalysisPhase Three - Develop Integrated SolutionsPhase Four - Implement

Organization	Yes or No	Question 1 Comment
		Solutions and Adjust System ProceduresIt seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the “Geomagnetic Disturbance Operating Procedure Template” for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs.Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >20kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
National Rural Electric Cooperative Association (NRECA)	No	NRECA recommends increasing the voltage level threshold from 200 kV to 345 kV. The drafting team has not provided a technical justification for choosing the 200 kV threshold. It appears that from the limited previous experiences associated with GMD events that there was no substantive impact on equipment at voltages below 345 kV. In addition, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast. The inclusion of the Balancing Authority as an applicable entity is not necessary. If the events being addressed in this standard are solely related to preventing transformer hot spot heating and voltage collapse through excessive use of reactive power, these types of events are managed by the Transmission Operator not the Balancing Authority. The Balancing Authority will only provide generation support as directed by the Transmission Operator.
SPP Standards Review Group	No	Please refer to our comment in Question 7 directed toward applicability in the SAR.
Pepco Holdings Inc & Affiliates	No	Recommend adding “BES” as qualifier for transformer.4.1.1 Reliability Coordinator 4.1.2 Balancing Authority with a Balancing Authority Area that includes any BES transformer with high side terminal voltage greater than 200 kV 4.1.3 Transmission Operator with a Transmission

Organization	Yes or No	Question 1 Comment
		Operator Area that includes any BES transformer with high side terminal voltage greater than 200 kV
Los Angeles Department of Water and Power	No	Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One - Assess and Baseline RiskPhase Two - Perform Technical and Programmatic AnalysisPhase Three - Develop Integrated SolutionsPhase Four - Implement Solutions and Adjust System ProceduresIt seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the "Geomagnetic Disturbance Operating Procedure Template" for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs.Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >200kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
seattle city light	No	Seattle City Light supports the general concepts presented in the draft Standard and appreciates that the Standard Drafting Team affords each entity flexibility as to procedures. However, Seattle is concerned about the broad applicability of the Standard as proposed, and recommends that it only apply to BA and TOPs with Bulk Electric System (BES) transformers 200kV and above (as well as all RCs). This change would make this Standard consistent with other Standards as well as the BES definition we've worked so hard on the past several years.

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	No	See FMPA concerns on aplicability, type of transformer, and whether or not the BA should be an applicable entity.
Arizona Public Service Company	No	Should only apply to transformers which are part of BES. BES definition is based upon the low side winding voltage of greater than 100 kV where as this requirement is based upon high side voltage. Thus, this goes beyond BES elements. We suggest it apply to transformer with low side winding voltage of 200 kV or greater.
Public Utility District No.1 of Snohomish County	No	SNPD agrees in general but believes the 200 kV voltage threshold is premature. In general, we believe that GMD should be tackled on a regional basis and already by the Reliability Coordinator ("RC"). It is our understanding that location (latitude and local geology) and the type of systems (i.e., systems with extra-high-voltage, series capacitor compensated lines, transformer configuration & grounding, and line length) are important elements in a GMD analysis. Therefore, a one-size-fits-all approach based on voltage level would be inappropriate. SNPD believes the Reliability Coordinator ("RC") would be in the best position to identify facilities including the appropriate voltage level or other attributes that may become more apparent as research in this area matures.
Foundation for Resilient Societies	No	Standards relating to Operating Procedures should apply to high side Transformers of 100 kV or higher. Despite higher resistance, transformers in the 100 kV to 200 kV range contribute a significant proportion of GICs that can destabilize the grid. TJ Overbye et al (2012)estimate less than 60% of total MVAR is captured in New England and Michigan if transmission under 230 kV is excluded from protection. New transformers in the 100 kV to 200 kV range are projected by the Energy Information Administration at about 20% of all new EHV transmission mileage planned for the 2012-2018 period. NERC must include generating entities, because existing studies suffice to demonstrate both vulnerability of GSU transformers operated by Generating entities and need for equipment monitoring at generator stators, and related operating procedures to protect generators in severe geomagnetic storms. GSU Generators are at greater risk than generally recognized. See studies by Legro, Abi-Samra and Tesche at ORNL (1985); Walling &

Organization	Yes or No	Question 1 Comment
		Kahn (1991); J G Kappenman, Storm Analysis Report R-112, section 8 (2011); and Luis Marti, "Generator Thermal Stress during a Geomagnetic Disturbance" (2013). Of critical importance, the President of the United States has existing legal authority to order the de-energizing of electric generating facilities that are oil or gas-fired if an emergency so requires. To utilize this authority upon confirmed space warning of a severe solar geomagnetic storm, it is essential that all generating entities serving the bulk power system be included in emergency operating procedure standards; their personnel be trained to validate and confirm de-energizing orders and procedures (and re-energizing procedures), with a multi-day strategic warning but only tens of minutes for tactical order, validation, and execution. Because most of the generating facilities serving the bulk power system are not now equipped with protective equipment that would enable these facilities to "operate through" a severe solar geomagnetic storm, it is essential that generating entities be included in the Operating Procedure coverage and standards. Further, the Nuclear Regulatory Commission has existing authority to order de-energizing and safe shutdown of the 102 NRC licensed nuclear power plants in the U.S. or a subset that are especially affected by a particular GMD event. Generating entities may need to review operating procedure options for rapid shutdown of generators if GSU transformers are not equipped with protective hardware. Beyond the practical necessity of including transformers and transmission equipment in the 100 kV to 200 kV range, FERC Order 779 applies to the entire bulk power system, which is now defined as commencing at 100 kV or above and not 200 kV or above. It would be illegal for NERC to exclude a significant proportion of the transmission line mileage (for many utilities more than half total EHV transmission mileage). Even if EHV transformers above 200 kV are later protected with neutral ground blocking equipment, leakage of GICs from lower voltage equipment will add significant Mvar into regional grids. FERC intended standards to protect the entire bulk power system of 100 kV or higher; NERC's participating entities should respect and support this federal policy.
DTE Electric	No	System study of areas potentially affected by GMDs should be identified before standard is written requiring all entities to have plans and operating procedures.
JEA	No	The applicable entities should't not include the BA but needs to include the GOs. Generator step up transformers are more critical to BES reliability than substation step down transformers. Only

Organization	Yes or No	Question 1 Comment
		BES transformers should be included.
Oncor Electric Delivery Complany LLC	No	The draft fails to include Generator Owners and Generator Operators that have step-up and auxillary transformers with a terminal higher that 200 kV. If GMD causes unintended ground induced currents (GICs) on Transmission Owners' and Transmission Operators Transmission Transformers that are important to the grid, then it stands to reason that step-up and auxillary transformers are at risk as well. Generator Owners transformers have a great impact to the reliability of the system. Those transformers need to be included in the Standard. Additionally, it would seem imperative to include generator owner transformers that supply offsite power to nuclear generation that are above 200 kV. The Standard must include the GO and GOP in order to address the FERC Order.
Puget Sound Energy	No	The drafting team should ensure that the voltage level in the applicability statement does not include elements excluded by the Bulk Electric System definition. Specifically, it appears that the applicability statement would include equipment excluded from the BES by the language of BES Definition Inclusion I1 ("Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher..."). Also, voltage level is not the only measure of GMD influence on the BES - there are other factors that the standard should include in its assessment of applicability, including grounding method, grounding resistivity, core type and transformer (coiled equipment) connections. Leaving these factors out of the applicability section means that many entities who are unlikely to be affected by a GMD event will be unnecessarily burdened with drafting procedures that they may never need. In addition, it is not clear why the Balancing Authority is included as an applicable entity - in general, the actions available to the operators are transmission system specific. However, if the Balancing Authority is removed as a responsible entity, the drafting team should ensure that generation interconnection facilities are also assessed for applicability with respect to the interconnected TOP.
NV Energy	No	The preparation and execution of operating procedures to mitigate the effects of GMD events on the power system are specific to the Reliability Coordinator and the Transmission Operator entities. We do not believe that actions are required of the Balancing Authority function at all, as this is not a balancing issue, but rather a transmission operations issue. Additionally, we

Organization	Yes or No	Question 1 Comment
		believe the scope of applicability should not reach into distribution transformers, particularly radial transformers serving distribution load. Hence, we recommend that the Applicability section be modified to remove 4.1.2 (Balancing Authority) and place a limitation on 4.1.3 to restrict applicability to BES transformers of the indicated voltage range.
LCRA Transmission Services Corp	No	The standard has not provided a clear reason for starting at 200 kV, which seems arbitrary. Papers on GMD do indicate the potential risk to transformer's increases at the higher voltage levels and in particular to single phase wye connected transformers. Would propose the following:4.1.3.1 a Transmission Operator Area that includes any BES transformer with three single phase core windings connected in a "wye" configuration of 300 kV or greater; or4.1.3.2 a Transmission Operator Area that includes any BES transformer with at least one "wye" connected winding greater than 400 kV;
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
Oklahoma Gas & Electric	No	This standard should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Tri-State Generation and	No	Tri-State believes that Balancing Authorities should not be included as an applicable entity because there will be unnecessary duplication or conflict between the BA and the Reliability

Organization	Yes or No	Question 1 Comment
Transmission Association, Inc.		Coordinator Operating Plans.
Texas Reliability Entity	No	We agree with the RC and TOP functions. The SDT may also want to consider adding the GOP function so that large GSU's are also monitored under this standard.
CenterPoint Energy	Yes	CenterPoint Energy agrees in general with the SDT proposal but has an alternative suggestion for the specific roles of the applicable responsible entities. Please see CenterPoint Energy's comments regarding Requirement 1 (Question 2).
City of Austin dba Austin Energy	Yes	During the July 30, 2013 GMD webinar, the response to one question was that the SDT would consider whether the BA applicability is appropriate. Austin Energy (AE) would encourage the SDT to complete that effort.
Northern California Power Agency	Yes	For Stage 1 I believe the SDT has it correct; however I am concerned that there is no mention as to what will happen with IRO-005-3.1a R3 which appplies to a host of registrations. At some point EOP-010-1 will supercede IRO-005-3.1a, but no mention in the implementation plan is discussed.
Emprimus LLC and Volkmann Consulting	Yes	For the Stage 1 standard, appropriate inclusion of affected transformers is not as important as it will be in Stage 2. What is important for the Stage 1 standard to capture in its applicability section the portion of the BES most effected by a GMD and the most influential to maintain BES reliability. In capturing RC, BA and TOP with 200kv transformers, the SDT has captured entities that have influence over the 200kv and above system. For entities the own and operate facilities between 100 and 200kv, their system reliability will be maintained by the RC and any neighboring / over-arching entities that operation 200kv and above.
Northeast Utilities	Yes	I agree with the applicability, however if the definition of BES changes I do not think this standard should apply down to those with transformers having high sides of 100 kV. The impact of GMDs and the magnitude of GICs is greatly reduced at these lower voltages and doesn't warrant the additional burden it would impose.

Organization	Yes or No	Question 1 Comment
PJM Interconnection, L.L.C.	Yes	PJM has also signed onto SERC's comments.
Santee Cooper	Yes	Recommend the SDT consider changing he high side terminal voltage on transformers to greater than 300 kV. The focus of the standard should be at higher voltages where the line length makes the lines more vulnerable to geomagnetically-induced currents.
Northeast Power Coordinating Council	Yes	The Applicability and Purpose conflict however. The Purpose says “To mitigate the effects of geomagnetic disturbances (GMD) events by implementing operating procedures.” But the Standard’s Purpose is not consistent with the Standard. The Standard goes into detail about the mitigation plans. Recommend the Purpose be “To establish and implement GMD mitigation operating procedures”. The effectiveness of these procedures to mitigate the effects of GMD is unknown.
Southern Company	Yes	The currently drafted standard does not include GOPs as an applicable entity. Consideration should be made to include them as an entity for reliability purposes. For example, a GOP may decide to take a unit offline if a K7 is declared, and if so, the reliability entities would need to know that these units are not available, if needed. In addition, if GOPs are added as applicable entities, they need to have a requirement to provide their plan to the reliability entities. Although we are suggesting adding the Generator Operator as an applicable entity, we do suggest that they be allowed to develop their own GMD Operating Plan or implement the GMD Operating Plan of its Transmission Operator.We also believe, consistent with our response to Question #7 below, that the standard should not apply to BAs, as the the risks mitigated by requiring them to have Operating Procedures are things that the TOP monitors and can either take action themselves or instruct the BA to redispatch generation.
ReliabilityFirst	Yes	There may be cases in which a transformer with a high side terminal voltage of greater than 200 kV is not considered BES (e.g., the transformer is excluded as part of a local network). ReliabilityFirst requests clarification whether this non-BES transformer is included within the

Organization	Yes or No	Question 1 Comment
		scope of the standard?
Salt River Project	Yes	We agree that the scope is appropriate.
Entergy Services, Inc.	Yes	We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. One of the reasons for the change is due to the number of transmission to distribution transformers where the high side voltage is 230 kV. On the other hand, having the 200 kV cutoff has the potential to create confusion for BA. A BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces.
Duke Energy	Yes	While Duke Energy agrees in principle with starting at 200kV and above for having a GMD process/procedure, we believe that 300kV and above would be a more appropriate bright-line. In addition, if the bright-line remains at 200kV and above, we recommend the SDT should consider an alternative method of including only 200kV and above BES elements. Lastly, Duke Energy believes that only transformers with wye connected winding(s) should be included because only wye connected winding(s) are affected by GIC(s).
SERC OC Review Group	Yes	Yes. We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. In addition, if the original language (greater than 200kV), remains in the standard, there should be an exception for equipment such as transformers.
Hydro One Networks Inc.	Yes	
Dominion	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Western Area Power Administration	Yes	
Bureau of Reclamation	Yes	
American Electric Power	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Ben Li Associates	Yes	

Organization	Yes or No	Question 1 Comment
Electric Reliability Council of Texas, Inc.	Yes	
Xcel Energy	Yes	
Farmington Electric Utility System	Yes	
Luminant Generation	Yes	

2. **In Requirement R1, the SDT is proposing to require Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan. This coordinating role for the RC is based on the functional model and addresses the Order No. 779 directive to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view. The defined term "Operating Plan" provides the RC with latitude to determine specific activities necessary to achieve this goal. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on Requirement R1. The drafting team reviewed all comments and has incorporated changes into a revised version of EOP-010-1. These changes include rewording part 1.2 and measure M1 to improve clarity. The drafting team believes the revised version of EOP-010-1 achieves the necessary level of coordination required for effective planning and real-time operations while at the same time preserving the Transmission Operator's latitude to act based on system specific or localized conditions. The drafting team has added a new Requirement R2 to the revised version of EOP-010-1 to maintain the Reliability Coordinator's responsibility for providing space weather forecast information and specified that this requirement would become effective upon retirement of IRO-005-3.1a Requirement R3. A summary of comments and the drafting team's response is provided:

- **Recommendation to replace the word "implement" with "coordinate" in Measure M1, and to clarify what is meant by 'Implement'. Commenters stated that the measure was not consistent with the requirement, and that the additional information was needed about the SDT's intent.** The SDT discussed this suggestion and agreed that the measure and requirement needed to be improved for consistency. The SDT agrees with the spirit of the comment, and Requirement R1 and corresponding Measure M1 have been revised to clarify what is intended by “implement”. The SDT considers an operating plan, process, or procedure to be implemented by carrying out its stated actions. The measure now specifies that operator logs, voice recordings, or transcripts are the required evidence to show that the stated actions in an Operating Plan, Operating Process, or Operating Procedure have been carried out.
- **Recommendation to replace the word "all" with "applicable" in Requirement R1, Part 1.2. Commenters stated that the draft wording could cause confusion.** The SDT agrees with the spirit of the comment and deleted the word 'all'. The SDT believes that the applicability statement establishes to whom the requirement applies.

- **Recommendation to add Same Day Operations Time Horizon to Requirement R1. Commenters stated this addition would be appropriate.** Same-day Operations are described as routine actions required within the timeframe of a day, but not real-time. The SDT agrees with the commenter and has made a revision to the proposed standard.
- **Recommendation for a longer implementation period. Commenters stated that additional time was needed for coordination among applicable entities, or for additional studies or information.** The SDT is sympathetic to the challenge of completing the necessary coordination in a 6 month time period, but the 6 month implementation period was suggested in FERC Order No. 779. The intent of EOP-010-1 is to have applicable registered entities investigate the potential impacts to their system and equipment to the degree possible and establish reasonable operational steps to be taken to mitigate the impacts with the understanding that additional research is underway and will provide better information in the future. The SDT believes that some prudent steps can be taken in the absence of more complete information and that this standard is consistent with the directives in Order No. 779. The SDT anticipates that the process to achieve compliance with EOP-010-1 will require collaboration among the RC and all entities included in the RC's GMD Operating Plan.
- **Recommendation to modify the standard to require RCs to develop the Operating Procedures for entities in the Reliability Coordinator Area, which may be supplemented by optional procedures developed by TOPs. A commenter stated that in areas with a lower historical risk it is inefficient or ineffective for all TOPs to develop Operating Procedures. A commenter stated that when historical and physical evidence shows GIC conditions do not exist for a TOP then the RC should not be required to include them in their coordinating plans.** The SDT believes that the requirement to have Operating Procedures must apply to all applicable TOPs in each RCA. Response to GMD events will vary based on local conditions but a key feature to response is to ensure that all applicable entities are responding in a coordinated manner within the RC area. The RC's Operating Plan should provide the necessary level of coordination for efficiency and effectiveness. An RC's Operating Plan may include Operating Procedures, as defined in the NERC Glossary of Terms.
- **Comments that Requirement R1 lacks specificity. Some commenters stated that the RC was given too much latitude; some commenters stated that the RC should be required to establish trigger conditions and a means for verifying compliance within the RCA. Commentors stated that the wording in R1 and R3 is of a “fill-in-the-blank” nature.** The SDT believes that the variability in the impacts of GMD across the system, based on a number of factors, precludes the ability to develop prescriptive requirements for GMD response at the RC level. The term “fill-in-the blank” standards refers to standards that require a bulk power system user, owner, or operator to implement regional criteria that are not specifically part of a NERC Reliability Standard and is not applicable to EOP-010-1.
- **Recommendation to reword Requirement R1 so that the RC is responsible to "coordinate the development" of the GMD Operating Plan. Commenters viewed this as a more appropriate role.** The SDT has modified Requirement R1 to address this concern. The modifications and additional explanatory material are the SDT’s attempt to clarify the dual obligations of the RC to both coordinate the development of the Operating Plan but also to implement the Operating Plan.

- **Clarification of the RC's responsibilities for space weather notifications.** The SDT agrees with commenters that supported requiring the RC to provide GMD forecast information. The drafting team noted that IRO-005-3.1a Requirement R3 currently provides this obligation. However, NERC Board has approved IRO-005-4 which, would result in retirement of that requirement. The SDT has added a new Requirement R2 to the draft standard to clearly designate the RC as the entity to disseminate space weather information to the applicable entities and specified the conditions in the implementation plan for making Requirement R2 effective upon retirement of IRO-005-3.1a Requirement R3.
- **Recommendation to use the defined term "Operating Process." Commenters provided several views including a recommendation to substitute Operating Process for Operating Plan in Requirement R1, and substitute "Operating Process" for "Operating Procedure" in R3.** The SDT believes that "Operating Plan" is the correct defined term with respect to the requirement assigned to the RC. However, the term "Operating Process" could apply to the requirement assigned to the TOP, so the SDT has modified R3 to include Operating Process.
- **Recommendation to require post-event analysis of GMD response.** The SDT agrees that this can be a valuable practice to assess the effectiveness of the plans and procedures. It does not believe that the practice should be required in the standard. There are processes at NERC to perform post-event analysis, apart from the standards process. The NERC Events Analysis program supports the industry's post-event review and learning needs, and this includes emerging risks. Additionally the GMD Task Force provides a forum for best practices and learning that can include post-event reporting and analysis from participating entities.
- **Market concerns during GMD events. A commenter stated that the standard should address suspension of the market during GMD events.** NERC Reliability Standards are market-neutral and neither mandate nor prohibit any specific market structure. Pursuant to Order No. 693, NERC Reliability Standards should have no undue negative effect on competition and should not limit use of the Bulk-Power System in an unduly preferential manner. NERC Reliability Standards do not preclude market solutions to achieving compliance with standards. See the Reliability and Market Interface Principles available here: http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.
- **Clarifications, rewording, and recommendations to enhance coordination. Commenters expressed concerns over the burden being required of RCs to coordinate Operating Procedures, the perceived limits of their authority to resolve conflicts, requirements to ensure coordination among RCs, and how to determine that coordination has occurred.** The SDT believes that the RC has sufficient authority to resolve coordination issues with applicable entities related to GMD Operating Plans, Processes and Procedures in the Reliability Coordinator Area. This authority is consistent with the NERC Functional Model, the NERC Rules of Procedure, and existing standards including IRO-001. Furthermore, the SDT believes that an effective Operating Plan cannot be created without the RC assuring coordination among all of the applicable entities in its RC area as well as coordination with its neighboring RC(s). The SDT has provided additional explanatory information in the draft to clarify what is intended by coordination. Coordination has occurred when the applicable entities, in conjunction with the RC, have reviewed and accepted the content of both the RC Operating Plan and the applicable entities' respective Operating Procedures. To improve clarity Part

1.2 of Requirement R1 was changed from "A process for the RC to determine that the GMD Operating Procedures are coordinated and compatible" to "A process for the Reliability Coordinator to review the GMD Operating Procedures". The SDT believes the requirement to ensure coordination between and among RCs is addressed in existing IRO standards. (Refer to IRO-014, Requirement R1). Therefore, the SDT has not added a duplicate requirement for coordination between and among RCs.

- **Comments on the need for vulnerability assessments. Commenters stated studies were needed to develop procedures.** The SDT believes the stage 1 standard meets the directives contained in FERC Order No. 779. The SDT recognizes that EOP-010 may be implemented without vulnerability assessments and specific action triggers based on system studies. The SDT believes that prudent steps to manage impacts of GMD on the power system can be undertaken, even in the absence of vulnerability assessments and equipment-specific action triggers. The SDT agrees that system studies will result in improved Operating Procedures, which may be part of an entity's mitigation strategy in stage 2 of the GMD reliability standards.

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	(1) R 1.1: This requirement needs clarification. It refers to a GMD Operating Plan requiring "a description of activities designed to mitigate the effects of GMD events....". It is not clear whether the "activities" are intended to be performed by the Reliability Coordinator or refer to the Operating Procedures of the Transmission Operators / Balancing Authorities, or some other type of activity directed by the Reliability Coordinator, but performed by other entities. FERC Order 779 only referred to a possible "coordination " of Operating Procedures and that element is captured separately in R 1.2. (2) R 1.2: The requirement for "compatibility" of Operating Procedures causes concern and should be deleted. FERC Order 779 (Par. 38) specified that GMD standards "should allow responsible entities to tailor their operational procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology and system topology. While FERC also directed NERC to consider the "coordination" of such operational procedures, it did not require the "compatibility" of such procedures. Manitoba Hydro already has in place operating procedures to respond to GMD events. The role of Manitoba Hydro's Reliability Coordinator is to notify Manitoba Hydro of GMD events and disseminate information on present and forecasted storm levels. This would be appropriately viewed as coordination. However, requiring a Reliability Coordinator to determine the "compatibility" of several entities' Operating Procedures goes beyond coordination and begs the question of what happens if there is a determination that certain Operating Procedures are not compatible. Does the

Organization	Yes or No	Question 2 Comment
		Reliability Coordinator have the authority to direct an entity to adopt a different procedure? If so, it is not clear how it would be determined which responsible entity must change its procedures. Most importantly, this requirement erodes the discretion that was granted to Transmission Operators and Balancing Authorities under Order 779.
ACES Standards Collaborators	No	(1) Having another duplicative “operating plan” does not improve reliability on the bulk electric system. The reliability standards already require several types of plans that could be enhanced to address GMD events. While we agree that flexibility is better than specificity, we disagree with the approach that another plan is required. The drafting team should consider enhancing existing operating plans and other approaches to respond to the FERC directive.(2) We believe that NERC should respond to the FERC directive with an equally efficient and effective alternative to developing a new reliability standard. Since the new standard will be largely redundant with with existing standards requirements, there is technical justification to support an alternate approach. The alternate approach would include relying on existing standards requirements. For example, IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective.(3) A reliability standard is not always the best solution to address a reliability concern. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. We cannot support a standard that attempts to address the issue in broad generalities. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
JEA	No	A vulnerability study is required before good operating procedures can be developed
American Public Power	No	APPA suggests that the word “all” in Requirement R1.2, be replaced with the word “applicable.” APPA believes using the word “all” in this context will bring into applicability TOs and BAs that

Organization	Yes or No	Question 2 Comment
Association		have transformers below the 200 kV threshold. Replacing “all” with “applicable” will limit confusion and avoid conflict with the applicability section of the standard.APPA is also concerned with the words “coordinated and compatible” in R1.2. On the July 30th webinar the SDT stated that a full scale power flow analysis would be the ideal way for the RC to determine compatibility of various plans. APPA is concerned with the cost to TOs and BAs of meeting this “ideal” therefore we suggest that the SDT give guidance on acceptable alternatives.
Florida Municipal Power Agency	No	Bullet 1.2 puts RC’s in a position of responsibility without authority, or at least implies such. The bullet requires the RC to “determine” that the plans of the BAs and TOPs are coordinated. What happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? FMPA suggests looking at the EOP-006 and EOP-005 construct for guidance.And as stated in response to question 1, the BA should not be an applicable entity.
Minnkota Power Cooperative, INC.	No	Comment #1) Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.Comment #2) Suggest replacing the word “all” in R1.2 to “applicable”.Rationale: Using the word “all” could be interpreted such that TO’s and BA’s that have transformers below 200kV could be affected. Replacing “all” with “applicable” would avoid confusion, and be in alignment with the SDT intent.
Los Angeles Department of	No	Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled

Organization	Yes or No	Question 2 Comment
Water and Power		separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events.Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
Los Angeles Department of Water and Power	No	Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events.Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
Great River Energy	No	GRE agrees with the MRO NSRF on the suggested language change in M1 for clarity and also to replace "implemented" with "coordinated". M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an "event driven" measure but the Requirement is to "coordinate" GMD Operating Plans. By using "coordinate" (versus implement) within the Measure, the measure uses the same words as the Requirement.This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability

Organization	Yes or No	Question 2 Comment
		in particular locations. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
Northern California Power Agency	No	I think there is too much latitude given. The guidance document describes GMD as more a global issue; not just a regional issue. I believe the guidance document provides a good list of activities for an RC to start with, but that these activities should be consistent between various RCs as well as the process the RCs will use to determimne if the TOP and BAs are coordinated and compatible.
DTE Electric	No	Instead of each RC, TO and BA developing its own plan to mitigate effects of GMDs, the standard should state that each TO and BA have a plan to support its RC's GMD plan. If individually created, the plans may conflict.
PacifiCorp	No	PacifiCorp supports Florida Municipal Power Agency's position as it relates to Question 2. R1.2 requires the RC to "determine" that the plans of the BAs and TOPs are coordinated but it is not clear what happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? PacifiCorp supports FMPA's suggestion to look at the EOP-006 and EOP-005 construct for guidance.
American Electric Power	No	R1, 1.2We are concerned by requiring the RC to "coordinate" Operating Procedures, and determine their collective compatibility. Exactly what actions would demonstrate coordination, and how could compliance of it be proven or shown? The word "coordinate" is very subject to interpretation, and could be inconsistently applied in various audits.R1.2 states that the GMD Operating Plan shall include "A process for the RC to determine that the GMD Operating Procedures ... are coordinated and compatible." This could potentially result in different coordination requirements in different regions and consequently, prevent entities who are operating in multiple regions to use consistent procedures within an entity's service territory.
City of	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission

Organization	Yes or No	Question 2 Comment
Tallahassee - Electric Utility		Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOPs and BAs” with “applicable TOPs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
City of Tallahassee	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
City of Tallahassee	No	R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Farmington Electric Utility System	No	Recommend rewording R1.2 “A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.” FEUS has concerns with how the RC would ensure ALL the TOP and BA plans are coordinated and compatible. In addition, FEUS is unclear what demonstrates a plan is compatible.
NV Energy	No	Requiring the RC to develop and maintain a plan is an appropriate requirement; however, it is unclear what the RC must do under 1.2 to "determine" that the GMD Operating Procedures in its area are coordinated and compatible. Suggest a language change to "A process for the RC to review and coordinate the GMD Operating Procedures of all TOP's in the RC Area."
MRO NERC Standards Review Forum (NSRF)	No	Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read:M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate

Organization	Yes or No	Question 2 Comment
		that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.
Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) and Western Area Power Administration (WAPA) recommend that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
Oncor Electric Delivery Complany LLC	No	The proposed language of R1 assumes all Regions operate the same therefore in order to support the structure of Regions across the North American utility industry, Oncor recommends R1 be revisedto:”Each Reliability Coordinator shall coordinate the development and maintain a GMD Operating Plan with its Balancing Authority, Transmission Owners, Transmission Operators, Generator Owners, and Generator Operators that coordinate GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:” Oncor believes the RC should remain responsible for implementing the plan.
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to

Organization	Yes or No	Question 2 Comment
		determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
Puget Sound Energy	No	This requirement imposes a heavy burden on the RC. Understanding that some level of coordination is required, perhaps a lesser level of coordination will be acceptable, at least until phase 2 of the project is complete. Such coordination could be modeled after the approach in IRO-010, where the RC would set the specifications for the TOP Operating Plans and the TOP would be required to comply with those specifications.
Texas Reliability Entity	No	This wording in R1 and R3 are “fill-in-the-blank” type of requirements that NERC has been trying to move away from. We understand that Phase 2 of the GMD Standard project will provide additional details and clarification.
Tri-State Generation and Transmission Association, Inc.	No	Tri-State believes that the proposed standard, as written, is too vague and gives the Reliability Coordinator too much latitude to create plans as only it deems appropriate. It also does not provide for industry review of these plans beforehand. Requirement R1 appears to be a "fill in the blank" requirement, which FERC does not approve.
Emprimus LLC and Volkmann Consulting	No	We agree with the language of develop, maintain and implement a GMD Operating Plan. However, the requirement does not have any evaluation of whether the Operating Plan was appropriately and effectively implemented for an event. M1 should include a post-event evaluation activity and subsequent documentation of the plan implementation.
Salt River Project	No	We believe that the requirement should state that the Reliability Coordinator should establish triggers that are appropriate for the given geographical and system exposure for each TO or BA. We would suggest language such as the following:R1.1 The Reliability Coordinator shall create a preliminary assessment of the exposure for each BA and TO. The plan and procedures developed by the Reliability Coordinator shall establish trigger levels for initiating and terminating these

Organization	Yes or No	Question 2 Comment
		plans or procedures based on the preliminary assessment of exposure for each BA or TO.
Duke Energy	Yes	Duke Energy believes R1.2 should be changed to "Each Reliability Coordinator shall have an Operating Process to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities in the Reliability Coordinator Area are coordinated and compatible."
Public Utility District No.1 of Snohomish County	Yes	Appropriate implementation time should be given so that the RC has time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions. Although GMD and Geomagnetically Induced Currents ("GIC") have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufactures. Recent work presented at the 2013 IEEE PES General meeting by Emanuel Bernabeu, Dominion "Overview of GMD Phenomena and ways to study the impact on the transmission system" and Ramsis Girgis, ABB "Equipment issues transformers, (Major Concern)'s etc. -from the transformers committee, impacts on transformer fleet and new designs" will provide more insight into appropriate actions to be taken by the RC and impacted functions. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on how GMD can impact the BES and what level of risk does GMD pose compared to other adverse impact events. See IEEE Power & Energy article "Geomagnetic Disturbances" by IEEE Power and Energy Society Technical Council Task Force on Geomagnetic Disturbances, July/August 2013 pg. 71-78.
Bonneville Power Administration	Yes	BPA's position is that the primary entities responding to GMD events are the TOPs and BAs. BPA believes the RC should be required to develop the criterion for their Operating Plan in direct coordination with the TOPs and BAs in their area in order to avoid the RC developing a plan that may not be compatible with the region. Additionally, the RC should be the primary source of space/weather information and be required to disseminate that information to the TOPs and BAs in their area.
CenterPoint Energy	Yes	CenterPoint Energy agrees in general with proposed Requirement 1 but offers an alternative proposal on specific aspects of the Requirement. We propose that the SDT modify R1 to read as

Organization	Yes or No	Question 2 Comment
		follows: Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan consisting of Operating Procedures developed by the Reliability Coordinator and coordination of GMD Operating Procedures that may be developed by individual Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.Discussion: We believe it is not necessary, beneficial, or efficient for each and every applicable Transmission Operator and Balancing Authority to try to develop GMD-related Operating Procedures and for the Reliability Coordinator to then try to harmonize multiple individual Operating Procedures in a way that benefits the region as a whole. We believe the most efficient and beneficial approach is for the Reliability Coordinator to develop an Operating Plan for the region, but allow (not require) individual Transmission Operators and Balancing Authorities to supplement the Reliability Coordinator's Operating Plan with individual Transmission Operator or Balancing Authority Operating Procedures, as along as those individual Operating Procedures, if any, are coordinated by the Reliability Coordinator.As repeatedly and correctly noted in the FERC Order, GMD assessment and mitigation requires a wide-area view. We believe some, if not most, individual Transmission Operators and Balancing Authorities will not be in a good position to reasonably determine what GMD-related operating actions would benefit the reliable operation of the entire region. Indeed, for some individual Transmission Operators and Balancing Authorities, it is possible and we believe likely that no action by that individual party is necessary or beneficial for the reliability of the region as a whole. The Reliability Coordinator has the wide-area view and is in the best position to determine what Operating Procedures would benefit the region as a whole. However, we also recognize that some individual Transmission Operators or Balancing Authorities may have already developed and implemented Operating Procedures, or may do so in the future based on specific concerns or vulnerabilities identified at some future time. We believe that it is beneficial to allow (but not require) individual Transmission Operators and Balancing Authorities to develop individual Operating Procedures based upon that entity's detailed knowledge and assessment of its facilities, as long as provision is made for the Reliability Coordinator to coordinate such discretionary individual procedures that would supplement the regional procedures.If the SDT agrees with CenterPoint Energy's proposal, the language of R1.2 would probably need to be modified by changing "...GMD Operating Procedures of all Transmission Operators and Balancing Authorities..." to "...GMD Operating Procedures of any submitted Transmission Operators and Balancing Authorities...". Also, R3 would need to be

Organization	Yes or No	Question 2 Comment
		modified. R4 and R5 would be deleted. CenterPoint Energy will discuss proposed changes to R3 in response to the next question.
Northeast Utilities	Yes	I agree that the RC should coordinate the plans for the BAs and TOPs in its area. It might be beneficial that there be coordination at the RRO level so that RC plans are coordinated as well, since GMDs/ GICs do not recognize arbitrary system borders.
Xcel Energy	Yes	In general, we agree with R1 & R1.1. However, we feel that R1.2 should be modified. Instead, we recommend the requirement read something like this: [1.2 A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.]
SERC OC Review Group	Yes	Language should be added to ensure coordination between adjacent RCs.
Entergy Services, Inc.	Yes	Language should be added to ensure coordination between adjacent RCs.
PJM Interconnection, L.L.C.	Yes	PJM has also signed onto SERC's comments.
Western Electricity Coordinating Council	Yes	Requirement is acceptable, but implementaiton period is too short
Southern Company	Yes	The SDT should consider creating criteria for the RC to use to ensure plans are coordinated and compatible. For example, criteria were developed for RCs to use to approve TOP restoration plans in EOP-006-2, R5, which indicates that the “Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its

Organization	Yes or No	Question 2 Comment
		Reliability Coordinator Area." Similarly, the SDT or a committee designated by the SDT should create criteria for RCs to use to ensure plans are coordinated and compatible.
Western Area Power Administration	Yes	Western Area Power Administration (WAPA) and the Bureau of Reclamation (Reclamation) believe that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, "A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event."
SPP Standards Review Group	Yes	While we concur that R1 addresses the FERC directive, we have some reservations with the use of the word 'coordinated' in R1.2 especially along the lines of what specifically will be required by the responsible entities to show coordination. Hopefully, the Reliability Coordinator will provide those details in his processes. Additionally, we would encourage the NERC Operating Reliability Subcommittee to ensure consistency in the processes used by the Reliability Coordinators throughout NERC.
Pepco Holdings Inc & Affiliates	Yes	
Hydro One Networks Inc.	Yes	
Dominion	Yes	
seattle city light	Yes	

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	
Oklahoma Gas & Electric	Yes	
FirstEnergy	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
Foundation for Resilient Societies	Yes	
Exelon and its Affiliates	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
ReliabilityFirst	Yes	

Organization	Yes or No	Question 2 Comment
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Ben Li Associates	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Company	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Luminant Generation	Yes	

3. In Requirement R3, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to develop, maintain, and implement GMD Operating Procedures. The draft Standard is intended to allow each entity to develop its own procedures based on entity-specific factors as directed in Order No. 779. Do you agree that the SDT has correctly addressed the stage 1 directives in Order No. 779? If you do not agree that this requirement addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The drafting team thanks all who commented on Requirement R3. All comments have been reviewed and the revised version of EOP-010-1 includes changes that the drafting team considers appropriate. Several changes such as the removal of BA applicability have been explained in preceding sections. The drafting team agrees that an “Operating Process” as defined in the NERC Glossary of Terms can satisfy the reliability objective of R3 and has modified the requirement so that it can be satisfied by either an Operating Procedure or an Operating Process. The drafting team modified part 3.1 which addresses space weather information in the Transmission Operator's GMD Operating Procedure or Operating Process. A summary of comments and the drafting team's response is provided below:

- **Avoid overlapping requirements for space weather information. Some commenters indicated that Requirement 3, Part 3.1 is unnecessary or could conflict with IRO-005-3.1a Requirement R3.** The drafting team believes that receiving space weather information is an essential component to GMD Operating Procedures or Processes. The drafting team changed the language in Part 3.1 from "steps or tasks for the acquisition and dissemination of space weather information" to "steps or tasks to receive space weather information". The change reinforces the RC's responsibility to provide information that is relevant to reliability, while recognizing that Transmission Operators may use several sources in addition to the RC's disseminated forecast information to obtain more detailed local or system-specific information.
- **A commenter suggested guidelines be developed by a technical committee.** The GMD Task Force, which reports to the Planning Committee, has developed technical resources including the 2012 GMD Report and the Operating Procedure templates, which are posted on the GMD Task Force page of the NERC website. Additional technical resources and operator training are included in the GMD Task Force project plan. EOP-010-1 is being developed in response to FERC directives.
- **Tailoring of operating procedures. A commenter requested that language be included in Requirement R3 to reflect that entities are allowed to consider various entity-specific factors in developing GMD Operating Processes or Procedures.** The drafting team agrees with the principle that an entity can consider entity-specific factors in developing its process and procedure. However the suggested language is not a measureable requirement for mandatory compliance and therefore this language has not been incorporated.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) The proposed standard is responsive to the FERC directive, but it fails to take into account existing reliability standards that overlap with the proposed draft, and creates duplicative requirements that could result in double jeopardy. For instance, TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Since the electric industry has always taken an “all hazards” approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. These policies and procedures would, therefore, be sufficient to respond to a GMD event without the need to make them specific to the GMD event or without the need to create a duplicative standard. The drafting team or a NERC technical committee, such as the Operating Committee, could draft a reliability guideline to provide additional detail of how to prepare for GMD events and make recommendations for utilities in areas susceptible to GMD events to include preparations in their planning processes.
National Rural Electric Cooperative Association (NRECA)	No	As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
Entergy Services, Inc.	No	As mentioned in Q1, a BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces and may need to develop, maintain, and implement GMD Operating Procedures. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
Florida Municipal Power Agency	No	As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority

Organization	Yes or No	Question 3 Comment
		within the standards to require that additional unit commitment or redispatch.
City of Austin dba Austin Energy	No	Austin Energy (AE) believes that staggered enforcement dates between R1 and R3 are necessary for TOPs and BAs to develop Operating Procedures “that are coordinated with [their] Reliability Coordinator’s GMD Operating Plan.” The current implementation plan establishes a single date for all requirements. During the webinar, AE suggested this and the response was that NERC anticipates that TOPs' Operating Procedures will be developed first so the timing is acceptable. Given the definitions of Operating Plan and Operating Procedures in the NERC Glossary, AE understands how an Operating Plan can be built based on a series of underlying Operating Procedures, but if that is the intended order of operation, R3 should not require that Operating Procedures be coordinated with the RC’s Operating Plan.
JEA	No	BA should be removed
Public Utility District No.1 of Snohomish County	No	Because GMD can be a wide area event the BA and TOP efforts should focus on coordinating operations and procedures with the RC. Also GMD is a High-Impact, Low-Frequency event so overall risk to the TOP or BA area should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
DTE Electric	No	Entities with no previous effects from GMDs should be exempted by their RX from developing a plan and entities with potential problems with GMDs should be required to develop plans to support their RC's plan and provide plan details to their RC.
Northern California Power Agency	No	In a perfect world this should already exist is folks are truely in compliance with IRO-005-3.1a R3. How are the RCs, TOPs and Bas curently complying with IRO-005-3a? This might provide some insight for the SDT.
NV Energy	No	OK, except "Balancing Authority" should be removed from R3.
PacifiCorp	No	PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 3. As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and

Organization	Yes or No	Question 3 Comment
		procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority to require that additional unit commitment or redispatch.
Salt River Project	No	Please see Comment for question 2. The requirements for the Reliability Coordinator should be the same for the Transmission Operator and Balancing Authority.
Foundation for Resilient Societies	No	Reason: Earlier comments on the Operating Procedure Templates submitted by the Foundation for Resilient Societies were ignored, and not addressed on their merits by the GMD Task Force management and by the NERC Planning Committee. See our previous comments at: https://resilientsocieties.org/images/Comments Operating Procedure Template NERC GMDTF Phase 2 Rev1.pdf.
Farmington Electric Utility System	No	Recommend revising 3.2. to the following, "The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator to mitigate the effects on the system from GMD events." FEUS agrees it is pertinent mitigating activities are coordinated; however, we believe this level or coordination should be in line with what is expected for coordination activities during a restoration.
Xcel Energy	No	Recommend revising R3.1. It isn't clear as to what periodicity that an entity should be collecting and disseminating this information. Also, it is unclear as to what would qualify as a source to meet this requirement (i.e. is any 'space weather' source acceptable?). Suggest removing this requirement and indicate in prior requirement (R1) that RCs have the responsibility of collecting and sharing space weather information with TOPs and BAs, and RCs must subscribe to an authoritative space weather source.
Arizona Public Service Company	No	Requirment 3.2 requires coordination with Reliability coordinator's plan. Thus, there should be a provision that this requirement is effective only 6 months after the Reliability coordinator's plan is available.
CenterPoint	No	See CenterPoint Energy's response to the previous question. In this question, the SDT states,

Organization	Yes or No	Question 3 Comment
Energy		"The draft Standard is intended to allow each entity to develop its own procedures...". There is a difference between allowing each entity to develop its own procedures and requiring each entity to do so. R3, as proposed, would do the latter. CenterPoint Energy's proposed changes to R1 would allow, but not require, an individual entity to develop its own procedures that would supplement required regional procedures developed by the Reliability Coordinator. If the SDT agrees with CenterPoint Energy's proposed change to R1, R3 would be modified to require Transmission Operators and Balancing Authorities to submit individual Operating Procedures, if any are developed, to the Reliability Coordinator so that the Reliability Coordinator could ensure coordination that would benefit the region as a whole.CenterPoint Energy also has specific concerns that R3.1 is unnecessary and unduly prescriptive. On page 24 of the FERC Order, FERC describes NERC's concern with reliance upon the most familiar means of characterizing space weather information, the "K-Index". On Page 30 of the Order, FERC acknowledged NERC's concern and took no position regarding overreliance on the K-Index to trigger operational procedures. R3.3 appropriately allows the responsible entity to choose and then document for compliance what the trigger mechanism would be, which could be space weather information or some other mechanism (GIC monitoring, for example). If an individual entity concurs with NERC's view that space weather information is an unreliable means of triggering Operating Procedures, then that entity should not be required to acquire and disseminate such information.Proposed language changes to implement CenterPoint Energy's suggestions are as follows:R3 Each Transmission Operator and Balancing Authority that chooses to develop, maintain, and implement Operating Procedures to supplement the Reliability Coordinator's Operating Plan described in R1 shall submit such supplemental Operating Procedures to the Reliability Coordinator for review and approval. 3.1 DELETED 3.2 DELETED (addressed by R1.1) 3.3 Moved to Requirement 1 as R1.3R4 DELETED (addressed by R2)R5 DELETED
Texas Reliability Entity	No	See comments for #2 above.
Seminole Electric	No	Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of various entity specific characteristics in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole

Organization	Yes or No	Question 3 Comment
		proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures:"An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures."Seminole believes that this is not clear in the Requirement and wishes that the NERC SDT specifically state the ability for an entity to tailor their plans and/or procedures to their environment. In addition, the suggested language is pulled from the SAR for this project.
NIPSCO	No	There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, the TOP should not be required to have plans specifically for GMD events.
Oklahoma Gas & Electric	No	This standard should not be applicable to the Balancing Authorities. FERC Order No. 779 directed the ERO to develop 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. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Western Area Power Administration	No	WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation believe it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch

Organization	Yes or No	Question 3 Comment
		or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address "The steps or tasks for receiving and disseminating space weather information to its System Operators."
Bureau of Reclamation	No	WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation suggest that it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2 respectively. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address "The steps or tasks for receiving and disseminating space weather information to its System Operators."
Emprimus LLC and Volkmann Consulting	No	We agree with the language stated in R3. However, R3 should include the requirement of the TOP to communicate that they have implemented their Operating Procedures. Likewise the requirement does not have any evaluation of whether the Operating Procedures were appropriately and effectively implemented for an event. M3 should include a post-event evaluation activity and subsequent documentation of the plan implementation
Los Angeles Department of Water and Power	No	While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could

Organization	Yes or No	Question 3 Comment
		lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Los Angeles Department of Water and Power	No	While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Sacramento Municipal Utility District	No	
Ben Li Associates	Yes	1. We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a. 2. It R3 is to be retained, then it does not mention "applicable" BAs and TOPs, which it should. Further, a BA or TOP should be able to adopt a template procedure developed by its Reliability Coordinator. This should be explained in an administrative appendix to the standard.

Organization	Yes or No	Question 3 Comment
Idaho Power Company	Yes	Agree in General. Propose adding Generator Operator to R3 and M3. The Reliability Coordinator needs to coordinate their procedures with the Transmission Operator, Balancing Authority and Generator Operator.
Southern Company	Yes	An additional requirement should be added requiring BA/TOPs to send their initial plans and any revisions to the RC for review, since the RC has responsibility for ensuring plans are coordinated and compatible.
Great River Energy	Yes	Because of the wide-area nature of a GMD event, GRE is suggesting a higher level authority such as the NERC Operating Committee or a NERC technical committee consider drafting guidelines to provide details in preparing for GMD events that would include recommendations to entites in areas susceptible to GMD events.
PJM Interconnection, L.L.C.	Yes	PJM has signed onto SERC's comments. PJM also signs onto the SRC's response to Question #3.
Exelon and its Affiliates	Yes	R3.3, font is incorrect - need the entire number to be bold.
Northeast Utilities	Yes	The language in R3 is adequate.
Tri-State Generation and Transmission Association, Inc.	Yes	Tri-State agrees that R3 properly addressed FERC Order No. 779, but believes the implementation periods should be modified. A 6 month implementation period requiring the Reliability Coordinator to develop the Operating Plan and the Transmission Operator/Balancing Authority to develop the Operating Procedures is not suitable. The Transmission Operator/Balancing Authority needs time to ensure their procedures are in accordance with the Reliability Coordinator's Operating Plan so the implementation dates need to be staggered.
Independent	Yes	We agree with the proposed requirement. However, there currently exists a similar requirement

Organization	Yes or No	Question 3 Comment
Electricity System Operator		in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and BalancingAuthorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist asneeded in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a.
Electric Reliability Council of Texas, Inc.	Yes	We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says:R3. Each Reliability Coordinator shall ensure its Transmission Operators and BalancingAuthorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist asneeded in the development of any required response plans.With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedures in place and be required to monitor GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT propose retiring R3 of IRO-005-3.1a. If R3 is to be retained, then it does not mention "applicable" BAs and TOPs, which it should.
MRO NERC Standards Review Forum (NSRF)	Yes	
SERC OC Review Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Hydro One Networks Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Dominion	Yes	
seattle city light	Yes	
Northeast Power Coordinating Council	Yes	
FirstEnergy	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
Colorado Springs Utilities	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
The United Illuminating Company	Yes	
ReliabilityFirst	Yes	

Organization	Yes or No	Question 3 Comment
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County, WA	Yes	
Oncor Electric Delivery Complany LLC	Yes	
Minnkota Power Cooperative, INC.	Yes	
Duke Energy	Yes	
American Public Power Association	Yes	
Luminant Generation	Yes	

NERC

4. In Requirements R2 and R4 the SDT is proposing to require applicable entities to review their GMD Plans/Operating Procedures every 36-months. This periodicity would ensure improvements in the scientific understanding of GMDs can be incorporated into Operating Procedures in a timely manner as directed in Order No. 779. In Requirement R5, the SDT is proposing to require each applicable Transmission Operator and Balancing Authority to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms, which is consistent with other EOP reliability standards. Do you agree that the SDT has correctly addressed the directives in Order No. 779 in a manner that is good for reliability with these requirements? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The drafting team thanks all who commented on Question 4. The drafting team reviewed all comments and has incorporated changes into a revised version of EOP-010-1. The drafting team agrees that applicable entities will be required to review and update its GMD Operating Plans, Procedures, and/or Processes in order to meet the requirement to maintain them in Requirements R1 and R3. As a result, Requirements R2 and R4 from the initial draft of EOP-010-1 have been deleted in the revised version as administrative and duplicative, consistent with the Paragraph 81 criteria (submitted to FERC in Docket No. RM13-8-000). Additionally, Requirement R5 was determined to be unnecessary for reliability and deleted in the revision because Requirements R1 and R3 require that applicable entities implement their GMD Operating Plans, Procedures, and Processes. The drafting team believes that these revisions have produced a clear, high quality, technically sound and results-based standard.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	No	(1) Requirements R2, R4 and R5 meet one or more Paragraph 81 criteria and should not be written as separate requirements that will result in a separate violation for failing to conduct the review on a timely basis or failing to have a copy of the operating plan or procedure in the control centers. A requirement is subject to retirement under P81 if the requirement fits any of the following criteria: it is administrative in nature, requires data collection/data retention, purely documentation or reporting, requires periodic updates, concerns only a commercial or business practice, is redundant with other standards, hinders the protection or reliable operation of the BES, or has little, if any, value as a reliability requirement.(2) Requirement R5 is very

Organization	Yes or No	Question 4 Comment
		similar to CIP-003-3 R4 which requires the cyber security policy to be available to all personnel with access to or responsibility for Critical Cyber Assets. In the P81 NOPR, FERC recently proposed to approve retiring CIP-003-3 R4 because it is administrative and it would be not be practical to implement the cyber security policy if it was not available to personnel. Similarly, R5 would be redundant with R3 because R3 has an implementation requirement. How can the TOP or BA implement the operating procedure if it is not available to its operating personnel per R5? How would an auditor verifying that a copy of the plan in the primary and backup control rooms benefit reliability? It could be placed in these rooms with no notification to system operators and no training provided to system operators on the implementation. Obviously, this would not support reliability. Requirements R2 and R4 are similar to the NUC-001-2 R9.13 which compel the Nuclear Plant Generator Operator and Transmission Entity to review their agreement every three years. FERC also proposed to retire it. Thus, R2 and R4 should be removed. If some vestige R2 and R4 are to remain, they should be made a sub-part of R1 and R3 so that a separate violation is not recorded for failure to review in the 36 month time frame. (3) We do agree that the 36-month time frame for review is reasonable.
Dominion	No	As R2 and R4 are currently written, they are purely administrative and do nothing to improve or insure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.
Sacramento Municipal Utility District	No	Every 36 months is too short of a time-frame. It would be more appropriate to have a review of a potential plan, if indeed needed, when system configurations warrant a review. The review period should be set by the entity, IF there is even a concern.
Exelon and its Affiliates	No	Exelon believes that performing a review of GMD Plans / Operating Procedures every 36 months is contrary to the Paragraph 81 criteria whose effort was to remove truly administrative requirements that do not have an impact on electric grid reliability. We feel tha R2, M2 and R2, M4 should be removed.
NextEra Energy	No	NextEra Energy is pleased with the work the GMD SDT has done in a very quick period of time, with the exception of adding certain requirements that no longer fit within the paradigm under

Organization	Yes or No	Question 4 Comment
		which Standards are to be drafted. NextEra suspects that these requirements were added because of the short period of time in which the SDT drafted the Standard, and, thus, NextEra is hopeful that once highlighted here that the SDT will quickly decide to delete the requirements as they are inconsistent with current Standard drafting practices. These requirements are inconsistent with both results based and P81 concepts, given that they are administrative in nature and do little to promote reliability. While some may see these requirements as good practices, adding them is no longer consistent with Standard drafting practices nor desired by stakeholders. New Standards are to be clear, high quality, technically sound and results based. Also, these requirements are similar to those that FERC recently indicated it would approve for retirement in the P81 Notice of Proposed Rulemaking. Therefore, NextEra requests that these requirements, noted below, be deleted. R2. Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. R4. Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date.
PacifiCorp	No	PacifiCorp affirms that if the intent of a review of an entity's GMD plans and procedures is to improve the scientific understanding of GMDs, a more prudent requirement would be a periodicity that is post-operative event based.In the absence of a GMD event, the 36-month requirement is arbitrary and one that would likely be performed by an entity as a best business practice.
DTE Electric	No	Please see previous comments from Questions 1, 2, and 3.
Entergy Services, Inc.	No	R5 is an administrative requirement for which compliance may be unprovable. This requirement (to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms) is also redundant to PER-005, which requires a Job Task Analysis for every task performed by System Operators. All administrative requirements should be deleted.
Electric Reliability Council of Texas, Inc.	No	Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is

Organization	Yes or No	Question 4 Comment
		unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operatinbg personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.
Hydro One Networks Inc.	No	Requirement R5 is of a purely administrative nature, not contributing to reliability. Suggest to eliminate. Emphasis and focus should be in operating personnel training and awareness. If R5 is kept in the standard, request to clarify the meaning of "prior to its implementation date." We believe it should be "prior to actions to implement the plan." As written in could be misinterpreted as prior to the standard effective date.
Arizona Public Service Company	No	Requirement R5 is unnecessary and should be deleted altogether. This requirement is a process and not a standard and it is not necessary to have a hard copy when an electronic copy could be readily available. There is no reliability benefit to this requirement.
Pepco Holdings Inc & Affiliates	No	Requirement R5 seems administrative in nature (similar to other Paragraph 81 requirements) and seems duplicative of R3 which already requires implementation of the Operating Procedures (i.e. implementation could include making operation personnel aware of the Operating Procedure and having available). If a separate training requirement is developed, R5 would be further redundant. Recommend that R5 be removed.Requirement R2 and R4 require applicable entities to review their GMD Plans/Operating Procedures every 36-months. With solar cycles having an average duration of about 11 years and the Plan and Operating Procedure being potentially utilized 1-2 years during the peak years of the 11 year cycle, how was the 36 month review criteria reached? Recommend changing to a 48 month review period which still allows for 2-3 reviews during a 11 year solar cycle.
FirstEnergy	No	Requirements R2 & R4FirstEnergy questions the need for Requirement R2 and R4 which propose an every 3-year review of GMD operating procedures. This is an administrative task and should not be a reliability requirement subject to mandatory enforcement. The requirements do not adhere to principles identified by the Par. 81 team and now being applied across all drafting teams. Par 81 Criteria B1 Administrative which states "The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not

Organization	Yes or No	Question 4 Comment
		support reliability and is needlessly burdensome." Additionally, an upcoming draft revision to the NUC-001 standard is proposing to remove a similar obligation in NUC-001 (R9.1.3). FERC's Order 779 did not suggest a need for the responsible entities to periodically update their GMD Operating Procedures every 3-years. Rather in paragraph 39 the Commission states "While responsible entities will develop and implement operational procedures, NERC can support their efforts, for example, by identifying and sharing operational procedures found to be the most effective. NERC should also periodically survey the responsible entities' operational procedures, offer recommendations based on lessons-learned and new research findings, and re-evaluate whether modification to the Reliability Standards is warranted." It is our understanding that it's the ERO's responsibility to reconsider whether or not more specific minimum GMD procedure expectations should be codified in the standard at some future date. This could be done for example during the 5-year review period of the standard and the NERC GMD Task Force could be tasked with providing the review required of NERC and propose changes to the GMD standard if needed.Requirements R5Requirement R5 indicates a need for the Operating Procedures to be located at the primary and back-up control center facility. The intent of Requirement R5 is already covered in standard EOP-008-1, R2. FirstEnergy recommends that Requirement R5 be struck as a redundant obligation.
The United Illuminating Company	No	Requirements R2 and R4 t to review the plan is purely administrative. As the scientific knowledge evelves R1 and R3 requires a plan to be designed to mitigate the effects of GMD.
American Electric Power	No	Requirements R2 and R4 state that each applicable entity shall review its GMD Operating Plan/Procedures every 36 months from the last *effective* date while Requirement 5 states that the applicable entities shall have a copy of its GMD Operating Procedures in the control room(s) prior to its *implementation* date. AEP recommends referencing the effective date only.R5 should be changed to state "...shall have a hard or electronic copy of its GMD Operating Procedures..."
Northeast Power Coordinating	No	The review interval specified in R2 and R4 is 36 months. A five year review would be more appropriate given the length of the solar cycle.As R2 and R4 are currently written, they are purely

Organization	Yes or No	Question 4 Comment
Council		administrative and do nothing to improve or ensure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.Requirement R5 also is administrative, does not contribute to reliability, and can be eliminated. Suggest to eliminate the wording “All procedures should be at the primary and backup control center as part of normal business”. Emphasis and focus should be on operating personnel training and awareness.If it is decided to keep R5 in the Standard, request clarificiation of the meaning of “prior to its implementation date.” It should be “prior to actions to implement the plan.” As written it could be misinterpreted as prior to the Standard’s effective date.
SPP Standards Review Group	No	To address timing issues in R5, we suggest inserting the word ‘current’ between the ‘a’ and ‘copy’ and deleting the phrase ‘so that it is available to its operating personnel prior to its implementation date’. R1 would then readEach Transmission Operator shall have a current copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms. For consistency with EOP-005, we would suggest that the VRF for R5 be reduced to Low. This is an administrative requirement and does not merit a Medium VRF.Additionally, we wonder why the Reliability Coordinator is not required to have a copy of its GMD Operating Plan in its primary and backup control centers.
Great River Energy	No	With NERC’s Relaibilibity Assurance Initiative (RAI), the P81 initiative and the work performed by the Independent Expert Review Project, R2 & R4 are administrative in nature and suggest the drafting team remove these two requirements. Similarly, R5 is also in administrative and is redundant with R3 because R3 has an implementation requirement. Per the P81 NOPR, CIP-003-3, R4 which required the cyber security policy be available to all personnel with CCA responsibilities, has been approved to be retired.
Oklahoma Gas & Electric	Yes	We agree with the language of these three requirements, however, we believe that the Violation Risk Factor should be LOWER, not Medium for these documentation related requirements.
ReliabilityFirst	Yes	1)Requirement R2 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan” at the end of the requirement.

Organization	Yes or No	Question 4 Comment
		ReliabilityFirst suggests the following for the SDTs consideration: "Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date [of its GMD Operating Plan]."2) Requirement R4 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan.” ReliabilityFirst suggests the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date [of its GMD Operating Procedures]."
Idaho Power Company	Yes	Agree in General. Propose adding Generator Operator to R4, M4, R5 and M5. Many of the other standards are using a five year review cycle. The review requirement should also include a trigger based on system upgrades or major changes to system topology.
NV Energy	Yes	Agree with the 36 month cycle of review; however, BA should be removed from R4.
Florida Municipal Power Agency	Yes	Although FMPA agrees with a 3 year period, FMPA would prefer a requirement of once every 3 calendar years as opposed to 36 months to allow more flexibility in scheduling.Again, the BA should not be an applicable entity.
Los Angeles Department of Water and Power	Yes	Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Los Angeles Department of Water and Power	Yes	Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
PJM Interconnection, L.L.C.	Yes	PJM has signed onto SERC's comments.
Independent Electricity System	Yes	Requirements R2 and R4 could easily be combined. Is there a specific reason why the Reliability Coordinator is separated from the Transmittion Operator and the Balancing Authority? The

Organization	Yes or No	Question 4 Comment
Operator		wording in these two requirements is identical.
Northern California Power Agency	Yes	Yes, but I do not see that this is any different form complying with IRO-005-3 R3 except for the 36 month review cycle.
MRO NERC Standards Review Forum (NSRF)	Yes	
SERC OC Review Group	Yes	
seattle city light	Yes	
Emprimus LLC and Volkmann Consulting	Yes	
Bonneville Power Administration	Yes	
JEA	Yes	
Salt River Project	Yes	
Western Area Power Administration	Yes	
Western Electricity	Yes	

Organization	Yes or No	Question 4 Comment
Coordinating Council		
Southern Company	Yes	
Bureau of Reclamation	Yes	
Colorado Springs Utilities	Yes	
Foundation for Resilient Societies	Yes	
CenterPoint Energy	Yes	
NIPSCO	Yes	
American Transmission Company	Yes	
LCRA Transmission Services Corp	Yes	
Public Utility District No. 2 of Grant County,	Yes	

Organization	Yes or No	Question 4 Comment
WA		
Ben Li Associates	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Public Utility District No.1 of Snohomish County	Yes	
Oncor Electric Delivery Complany LLC	Yes	
Minnkota Power Cooperative, INC.	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Duke Energy	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	
American Public Power Association	Yes	
Farmington Electric Utility System	Yes	
Luminant Generation	Yes	

5. If you have any other comments on this draft Standard that you haven't already mentioned above, please provide them here.

Summary Consideration: The drafting team thanks all who responded to Question 5. The drafting team reviewed all comments and has incorporated changes in response to suggestions from those comments into a revised version of EOP-010-1. A summary of comments and the drafting team's response is provided below:

- **One commenter suggested an appendix be included with the standard to support information sharing and learning.** The drafting team believes this activity should be addressed through existing mechanisms and not through additional requirements. The NERC Events Analysis program supports the industry's post-event review and learning needs, and this includes emerging risks. Additionally the GMD Task Force provides a forum for best practices and learning that can include post-event reporting and analysis from participating entities.
- **Commenters stressed the value of studies and analysis; some recommended that the ordering of stage 1 and stage 2 in the SAR and FERC Order should be reversed.** The drafting team agrees that detailed studies such as those that may be required in stage 2 will provide a better assessment of risk and more appropriate and effective mitigation measures. However, there are prudent measures to mitigate risk from a GMD event that can be implemented without detailed system impact studies. The drafting team believes EOP-010-1 provides a reliability benefit as written and meets the directives in FERC Order No. 779.
- **One commenter suggested changes to language used in the effective date section of the standard.** NERC Legal worked with a representative of the Canadian Electricity Association to revise the language to ensure it appropriately reflects the current mechanisms for making standards effective in each of the Canadian provinces.
- **Suggestions for an alternate approach to meeting the directives through existing standards**. **Some commenters disagreed with the drafting team's approach to meeting the stage 1 directives contained in FERC Order No. 779 with a new standard. Commenters argued for modifications to existing standards or a response to the FERC directive that points to existing requirements to avoid duplicating requirements.** The drafting team agrees that existing standards including IRO-014, EOP-001, and TOP-004 could be modified to meet the directives in the order. However, the drafting team recognized the challenges of developing and successfully balloting the stage 1 standards within the deadlines established by the order and chose to create a single new standard. We respect the view of some stakeholders that an alternate approach would have been preferred. The drafting team also agrees that existing requirements that are applicable at all times provide some mitigation during GMD events; however, this approach does not meet the directives in Order No. 779. The drafting team did not write prescriptive requirements for real-time actions to mitigate GMD events, which would duplicate TOP-001. Furthermore, planning and policy requirements contained in TOP-002, TOP-004, and EOP-001 do not meet the specific directives of FERC Order No. 779 as written.

- **A commenter supported the technical work but considered the posting of the draft standard for ballot simultaneously with the SAR to be a violation of NERC Rules of Procedure.** The scope of the current project was set forth in detail by the Federal

Energy Regulatory Commission in Order No. 779 and there is a January 2014 deadline associated with the project. The decision to simultaneous post the SAR and the proposed Reliability Standard with a ballot conducted during the last ten days of that comment period was approved by the NERC Standards Committee. We respect your disagreement with this process decision and hope that you will continue to participate in the development of this standard.

- **Comments provided about draft GMD Task Force Planning Application Guide were considered out of scope for Stage 1 standards. Specific comments on the GMD Task Force Operating Procedure template were reviewed and did not affect the development of EOP-010-1 requirements but are valid points to consider in developing an entity's Operating Procedures.**
- Several suggestions for changes to wording were provided, considered, and incorporated into revisions when the drafting team agreed that they provided an improvement. The drafting team did not agree with comments suggesting the removal of the Long-term Planning Time Horizon from Requirements R1 and R3 because the required action, which is the development of Operating Plans, Processes, or Procedures, could take place years before a space weather event necessitating carrying out the actions in an entity's Operating Process or Procedure.
- The drafting team does not intend to produce a separate Guidelines and Technical Basis section for EOP-010-1, but has posted technical resources on the project page. The GMD Task Force page also contains technical references and task force products including the 2012 GMD Report.
- **Several commenters stated that Requirement R5 is not needed.** As noted above in response to Question 4, Requirement R5 was determined to be unnecessary for reliability and deleted in the revision since Requirements R1 and R3 require that applicable entities implement their GMD Operating Plans, Procedures, and Processes.

Organization	Question 5 Comment
Oklahoma Gas & Electric	While we understand the good intentions of FERC in Order No. 779, we feel that industry's time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
Manitoba Hydro	(1) Background - for clarity, consider replacing the words "can lead to" with [may result in]. (2) Purpose - for clarity, consider replacing the purpose section of the standard with the following sentence: "To [ensure plans, operating procedures, and resources are maintained and available] to mitigate the effects of geomagnetic disturbance (GMD) [emergencies on the bulk electric system.]" (3) M2 - consider revising the measure as follows:"Each Reliability Coordinator shall have evidence [showing] that it has

Organization	Question 5 Comment
	reviewed its GMD Operating Plan within the timeframe of Requirement R2. [Acceptable evidence could] include a dated review signature sheet or revision history." (4) 3.1, 3.2 and 3.3 - for completeness, start the sentence with [A listing of the]. (5) M4 - consider revising the measure as follows: "Each Transmission Operator and Balancing Authority shall have evidence [showing] that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4. [Acceptable evidence could include] a dated review signature sheet or revision history." (6) Table of Compliance Elements, R2, Low, Medium, High VSL - insert the word [last] before the words "effective date" for consistency with Requirement R2. (7) Some entities may reduce exports to neighbors as a mitigating strategy. This method, determined to be the ideal action, based on system studies, may be perceived as potentially impacting neighbouring entities. What level of coordination would be required or appropriate to permit the curtailment of exports?
ACES Standards Collaborators	(1) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will be viewed as this coordination. (2) The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions". A operating plan contains operating procedures and processes. (3) Part 3.1 in R3 is unnecessary because NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. There is not a need to codify a process that is already in place and works

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	effectively.
Western Area Power Administration	: WAPA and Reclamation also believe Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
ReliabilityFirst	1) Requirement R5 - To be consistent with the language in the other requirements within the standard, ReliabilityFirst recommends changing the term “implementation date” to “effective date.” ReliabilityFirst offers the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its [effective] date." 2) Consideration for new Requirement R6 - ReliabilityFirst recommends including a new Requirement R6 which would require adjacent Reliability Coordinators to share their respective GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators should be aware of each other’s GMD Operating Plans. 3) VSL Requirement R2 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "...but less than or equal to..." language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than [or equal to] 39 months, since the effective date."4) VSL Requirement R4 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "...but less than or equal to..." language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than [or equal to] 39 months, since the last effective date."
Tri-State Generation and Transmission Association, Inc.	1. Tri-State believes a 6 month implementation period isn't appropriate for this. This implementation period requires the RC to develop the Operating Plan and the TOP/BA to develop the Operating Procedures at the same time. The TOP/BA needs time to ensure their procedures are in line with the RC's Operating Plan so the implementation dates need to be staggered. 2. Tri-State also believes Stage 1 and Stage 2 should be reversed. Developing, maintaining, and implementing a plan without first conducting assessments and determining the risk is illogical. The Operating Plans should be based on the results shown of the assessments.3. There is a lack of evidence showing major damage and widespread outages due to a geomagnetic disturbance. There should be more studies performed before creating a Reliability

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	Standard in order to better determine the actual necessity of one. 4. Currently, Tri-State believes that a guidance document would be a better solution to address the risk of potential geomagnetic disturbances.5. Tri-State believes all non-BES transformers should be excluded regardless of high side voltage. In addition any transformer with a delta primary winding should be excluded regardless of the high side voltage.
Independent Electricity System Operator	1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.If Requirement R5 was to be retained, we suggest adding “Reliability Coordinator” after “Transmission Operator” and “Balancing Authority”. We believe that Reliability Coordinators should also have a copy of their GMD Operating Procedures in their primary and backup control rooms. The current Requirement R5 does not include the Reliability Coordinator. 2. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”.The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
Ben Li Associates	1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.2. GMDs are an emerging issue. There is nothing in this standard that enables information sharing and learning. The RC plan and BA/TOP procedures should include what sensing information is in the field and the general reporting that such information gathering is done when GIC symptoms are observed. There should also be information collected following major solar events that is evaluated by the NERC technical committees. This should not be codified in the requirements, but

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	in an administrative appendix or an activity to be included in events analysis.
Salt River Project	A general comment on the Solar Cycle. It seems that the timing of the peak of the solar cycle might require more frequent review of plans and procedures. â€ƒ
Los Angeles Department of Water and Power	Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
Los Angeles Department of Water and Power	Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
Bonneville Power Administration	BPA agrees that operational procedures should be put in place but they will not have sufficient analysis of the full impact of certain actions due to certain technologies not being available at this point. Specifically, the reactive and thermal impacts of GMD on transformers.
CenterPoint Energy	CenterPoint Energy is hopeful that the SDT will agree with CenterPoint Energy's suggested changes. With CenterPoint Energy's suggested changes, we believe this standard can be reasonably applied throughout North America. If not, we believe the proposed standard is problematic for regions that have little or no GMD-related risk and ask that the SDT consider a proposal to exclude such regions from applicability. CenterPoint Energy understands that such a proposal would be subject to the Commission's review and approval but the FERC Order is clear that the Commission understands that there are different risks in different regions and the Commission does not endorse or order a "one-size-fits-all" approach. CenterPoint Energy believes candidate regions to exclude from these requirements would potentially

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	include ERCOT, SERC, and FRCC. However, to re-iterate our main point, we believe this standard could be applied to all regions, even those regions with minimal GMD-related risk, if CenterPoint Energy's proposed changes are accepted. Even for those regions that have more GMD-related risk than other regions, CenterPoint Energy believes it is problematic and, at best, inefficient, for each and every Transmission Operator and Balancing Authority in such regions to attempt to develop individual Operating Procedures intended to collectively enhance the reliability of the region as a whole.
Colorado Springs Utilities	Comments on Requirement 1: o In need to include a requirement for the RC to acquire and disseminate space weather information to the applicable entities within their footprint.Comments on Requirement 3: o From the glossary; Operating Procedure (in part): "The steps in an Operating Procedure should be followed in the order in which they are presented"; Operating Process (in part): "An Operating Process includes steps with options that may be selected depending upon Real-time conditions." The language in the Standard will be what is audited to, notwithstanding what any individual utility may titles their documents. The actions which may be required during a GMD event are far better presented in an Operating Process (as defined) than an Operating Procedure (as defined). There is no way that a TOP could follow the exact same step-by-step procedure for all GMD eventualities, but that is what the "Operating Procedure" term demands.Comments on Requirement R3.1: o Need to eliminate the requirement to acquire space weather information in R3.1, and have it a part of the information that the RC would disseminate to ensure consistency and coordination from the RC.Comments on Implementation Plan:1. Need to ensure that RC develops and disseminates their plan 1st with time included to incorporate RC plan into BA/TOP/GOP plans.2. Implementation period needs to be extended from 6 months to 12 months.
Northeast Utilities	Comments on the Geomagnetic Disturbance Operating Procedure Template:Transmission Operator: Information and Indications:Triggers: External: Watch, Warning and Alert K index numbers are too low. K-index is known to be an unreliable predictor of GMD severity, however it makes no sense to activate procedures below K7.Triggers Internal: System-wide/ equipment-level: Parameters mentioned could be abnormal due to other causes. There should be corroborating evidence cause is GMD before entering procedure.Actions Available to the Operator: Should specify that the actions are not limited to those listed.Long lead-time: Safe system posturing (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area

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	to ensure that other entities are not negatively impacted- not just a state estimator study.Remove shunt reactors: some systems auto switch reactors. These (and capacitors) should be left in auto so that they can respond to voltage swings.Day-of-event: Increase situational awareness: These require being able to corellate the observed parameters to equipment/ system effect before taking actionsPrepare for unplanned capacitor bank/SVC/HVDC tripping: Should add that multiple installations should be evaluated as a single contingency.Real-time actions: Safe system posturing (only if supported by study):Selective load shedding: No guidance is provided as to how this could help in a GMD.Manually start fans/pumps on selected transformers: Due to the hazard of potential catastrophic failure from static electrification caused when oil temperature is below 50 C, this section should not be mentioned.System reconfiguration (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study.Return to normal operation: Why is any time limit mentioned at all?
SPP Standards Review Group	Delete the phrase ‘and submit(ted) them for approval’ from the VSLs in R4. R4 does not require approval.
Duke Energy	Duke Energy believes that “Same Day Operations” is a more appropriate time horizon for R1 and R3.
El Paso Electric Company	EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 year long implementation period instead.
Farmington Electric Utility System	FEUS appreciates the work by the SDT team to allow entities flexibility when developing their operating procedures for mitigating GMD. The flexibility allows for entities to develop the plan that works with their system
Southern Company	For R3.1, to address potential confidential data issues, the weather data utilized should be publicly available . We recommend changing R3.1 as follows:R3.1 The steps or tasks for the acquisition and dissemination of publicly available space weather information to its System Operators.

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NextEra Energy	For the same reasons provided in response to question number #4 (P81 -- administrative in nature), NextEra requests that the following requirement be deleted: R5. Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date.
Public Utility District No. 2 of Grant County, WA	GCPD is concerned about the implementation period being sufficient to allow the RC to develop and implement a GMD Operating Plan AND afford adequate time to ensure that each TO and BA within its region the ability to develop, maintain and implement GMD Operating Procedures that are coordinated with the RC's GMD Operating Plan. Six (6) months is not sufficient time to allow development and coordination within the region.
Great River Energy	GRE agrees with ACES, The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on “Real-time conditions”. A operating plan contains operating procedures and processes.
Arizona Public Service Company	Implementation time for BA and TOP should have 6 additional months than the implementation time for Reliability coordinator. This is to allow coordination wiht Reliability Coordinator’s procedures affecting BA and TOP.Requirement R1, 1.2 should have the word “all” deleted. It does not serve any specific purpose and could become unnecessarily burdensome.
American Electric Power	In the VSL matrix, R4 states that “the responsible entity reviewed its GMD Operating Procedures and submitted them for approval....”. Requirement 4, as stated, does not require approval for the Operating Procedures, therefore the words “and submitted them for approval” should be deleted from all four VSLs for R4.

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Luminant Generation	Luminant has voted Negative as the posting and balloting of the GMD proposed standard did not follow the NERC Rules of Procedure. Luminant appreciates the technical work of the Ad Hoc group but believes the standard should have been posted for comments only, instead of being posted for balloting.
Texas Reliability Entity	Many new Standards have a Guidelines and Technical Basis section as part of the Standard. Would the SDT consider creating a Guidelines and Technical Basis section?
LCRA Transmission Services Corp	none
National Rural Electric Cooperative Association (NRECA)	NRECA is does not believe that it is necessary to develop a separate GMD standard to address requiring Operating Procedures for GMD events. Criteria for addressing such events can easily be added to existing standards that require entities to have Operating Procedures. Suggesting a new standard that has similar requirements as existing standards does not adhere to the spirit of the P81 initiative to eliminate unnecessary duplicative requirements. Examples of requirements that could be revised to address GMD events are: IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other Reliability Coordinators. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. R5 - NRECA agrees that it is reasonable to require that a copy of an applicable entity's GMD Operating Procedures is in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date. In the Time Horizon designation for the requirements of this standard, the "Long Term Planning" horizon should be removed. As written, this standard addresses Operating Procedures to address Real-time events not those that meet the criteria for a "Long Term" event.
City of Austin dba Austin Energy	Overall, AE has voted negative because there is an abundance of cleanup work necessary. AE asks the SDT to consider the comments above as well as the following points:(1) The SDT should more carefully consider the wording for the applicability of transformers. During the webinar, someone asked if the intent was to cover only BES tranformers and Mark Olsen answered in the affirmative. As written, the BES definition considers the low-side voltage (greater than or equal to 100 kV), whereas the Applicability section of EOP-010-1 considers only the high-side voltage. There could be transformers that are 69/230

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	kV that would not be BES Elements but would bring in a TOP or BA given the way 4.1.2 and 4.1.3 are currently written. Additionally, the SDT should consider transformers with high and low-side voltages greater than 100kV but excluded from the BES based on a documented exclusion or exception.(2) Given the requirement to "develop, maintain and implement" in R1 and R3, the SDT should consider adding in the same day operations time horizon to cover the "implement" action.(3) The SDT should clarify what is intended by "implement" in R1 and R3. During the webinar, the response to this question was unclear. SDTs on other recent projects (COM-003-1, for example) have gone to great lengths to define what is meant by "implement." RSAWs often state it means to include in your company's body of operating procedures. Without explanation, a CEA might interpret implement as follow your Plan/Procedure exactly as written. The industry needs to know the SDT's intent.(4) Change the word "all" to "applicable" before the phrase "Transmission Operators and Balancing Authorities" in R1 part 1.2.(5) The SDT should move the requirement regarding space weather (currently R3 part 3.1) to R1 so the RC can, in its coordination role, ensure that input data is consistent and applicable to its Region.
Emprimus LLC and Volkmann Consulting	R5 should be applicable to RC also.
The United Illuminating Company	Requirement R5 to make the operating plan available in the control center is administrative. Reliability requires the plan to be implemented as described in requirement R1. VRF for R1 and R3 are Medium since an entity failure to implement the GMD operating plan may lead to cascade. VRF for R2, R4, and R5 should be Low. R2, R4, and R5 are purely administrative. The entity is required to have Operating Plans that mitigate the effects of GMD a review of the operating plan is a secondary activity to developing, maintaining, and implementing an operating plan.
Minnkota Power Cooperative, INC.	See NSRF Comments
Western Electricity Coordinating Council	Six Month implementation period is not adequate
Sacramento Municipal	SMUD also has concerns with the implementation period and questions whether or not six months is

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Utility District	adequate time for the BA and TOP to develop the required GMD Operating Procedures and for the RC to develop the required Plan to coordinate those GMD Operating Procedures. SMUD also encourages the SDT to consider the GMD threshold application to be raised to 300+kV,and also encourages the Project 2013-03 Standard Drafting Team to consider the comments submitted by Florida Municipal Power Agency (FMPA) related to applicability of the standard.
City of Tallahassee	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
City of Tallahassee	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
City of Tallahassee - Electric Utility	Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC.The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. This reference is valuable to entity wishing to make an informed vote.
Transmission Agency of Northern California	TANC appreciates the performance flexibility that has been built into the current draft of this standard, but has concerns regarding the approximately six month implementation period between its approval and effective date. Of particular concern is the ability for each Reliability Coordinator to ensure coordination and compatibility between its GMD Operating Plan and the GMD Operating Procedures for all Transmission Operators and Balancing Authorities in its footprint during such an abbreviated period. As this initiative moves forward, TANC requests that NERC continue to carefully consider the scope of entities and assets that will be subject to this and subsequent standards so that the costs borne by the

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	industry are commensurate with the anticipated benefit to reliability.
FirstEnergy	The comments are supported by the following GMD standard ballot body members representing FirstEnergy: Bill Smith, Segment 1 Transmission Owners; Cindy Stewart, Segment 3 Load Serving Entities; Doug Hohlbaugh, Segment 4 Transmission Dependent Utilities; Ken Dresner, Segment 5 Electric Generators and Kevin Querry, Segment 6 Brokers, Aggregators, and Marketers.
Xcel Energy	The current IRO-005-3.1a R3 requires RCs to notify TOPs and BAs of certain GMD events. Consider deleting this requirement in IRO-005-3.1a as part of this implementation plan and add something in this standard (EOP-010) requiring RCs to make that notification. The pending approval of IRO-005-4 removed the explicit requirement, but development history indicates that it considers GMD to have an Adverse Reliability Impact that would require RC notification to entities.
Foundation for Resilient Societies	The Foundation for Resilient Societies has concerns that the NERC Planning Application Guide, developed without full public access to the related model assumptions, will mis-characterize geomagnetic latitudes with geographic latitudes; and will result in scientifically invalid assumptions that the NERC modeled "operating procedures" will suffice without need for hardware protections. For our Foundation review of the Draft NERC GMD Planning Application Guide, our review dated August 9, 2013, see: http://resilientsocieties.org/images/Resilient_Societies_Comments_on_GMD_Planning_Application_Guide_Final.pdf.
Hydro One Networks Inc.	There is a GMD related pre-existing requirement in IRO-005-3.1a R3. It seems, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF.The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date ",or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." to the end of the first sentence immediately after "by applicable regulatory authorities".The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
Northeast Power	There is a GMD related pre-existing requirement in IRO-005-3.1a R3. The implementation plan is not clear

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Coordinating Council	regarding the retirement of the requirement. It would seem, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF.Simpler wording would make the Standard easier to understand. Every plan will be different depending upon a wide range of factors affecting GMD mitigation; equipment types and inventory, location, system configuration and topography, latitude, ground characteristics, etc. Suggest the following simplifying wording changes to Requirement R3:R3. Each Transmission Operator and Balancing Authority shall develop, maintain, and implement GMD Operating Procedures. At a minimum, the Operating Procedures shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning] 3.1. The steps or tasks for the acquisition and dissemination of space weather information to its System Operators. 3.2. The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan. 3.3 The predetermined trigger conditions for initiating and terminating steps or tasks in the Operating Procedure.To be consistent with the terminology in other standards, suggest changing the wording the Applicability Section to:4.1.2 Balancing Authority with a Balancing Authority Area that includes transformers with high voltage terminals connected at 200kV and above.4.1.3 Transmission Operator with a Transmission Operator Area that includes transformers with high voltage terminals connected at 200kV and above.The wording of the Purpose should be changed to "To mitigate the risk of instability, uncontrolled separation, and Cascading in the Bulk-Power System as a result of geomagnetic disturbance (GMD) events by developing, maintaining and implementing Operating Plans and Operating Procedures." The Purpose as written should state what GMD affects. It also only addresses the implementation of the Operating Procedures but does not address the development and maintenance aspect, nor does it address the Operating Plans.
Northern California Power Agency	To suumarize:I will vote no on the initial ballot per comments I have submitted; however that does not mean I am opposed to this standard. I do believe GMD is an issue that even though it is low frequency can have an reliabiilty impact on the BES or BPS.I believe the SDT needs to address the IRO-005-3 R3 concern I have discussed. If I were to guess the reason for EOP-010-1, it would be to replace a pretty loose requirement in IRO-005-3 R3. If this is the case then give more direction and guidance in the new standard per the guidance document that NERC provided
Bureau of Reclamation	WAPA and Reclamation also believe that Generator Operators should have a role in developing Operating

Organization	Question 5 Comment
	Procedures that will affect their equipment.
Ameren	We believe GMD is a regional issue and therefore a NERC Standard is not necessary. We believe that studies need to be completed before considering a new NERC Standard. In addition, an entity cannot develop operating plans and procedures based on unstudied GMD conditions. After the initial assessments of potential impacts of GMD on BES reliability is complete, then appropriate (if necessary) plans and procedures can then be developed and if necessary a standard could then be drafted based on results of the studies.
MRO NERC Standards Review Forum (NSRF)	Would like clarification of the statement "last effective date" in the Table of Compliance Elements, Rows 2 and 4. Change the sentence to the following:"The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective date of the procedures"

Draft 2

Stage 1 Standard

Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The draft standard was posted for a 45-day formal comment period and initial ballot from June 26, 2013 through August 12, 2013. The SAR was posted for informal comment during the same period.

Description of Current Draft

This is the second posting of the proposed standard. It is posted for a 45-day formal comment period and additional ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	September 2013
Final ballot	October 2013
BOT adoption	November 2013

Effective Dates

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

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03	N/A

Definitions of Terms Used in Standard

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

None

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**
2. **Number:** EOP-010-1
3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator
   4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and protection system Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area.

> **Rationale and supporting information for Requirement R1:** An Operating Plan is implemented by carrying out its stated actions.
>
> Coordination is intended to ensure that operating procedures are not in conflict with one another.
>
> An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

R3. Each Transmission Operator shall develop, maintain, and implement an Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. Steps or tasks to receive space weather information.

3.2. System Operator actions to be initiated based on predetermined conditions.

3.3. The conditions for terminating the Operating Procedure or Operating Process.

M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

Rationale and supporting information for Requirement R2: Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Rationale and supporting information for Requirement R3: An Operating Procedure or Operating Process is implemented by carrying out its stated actions.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator and Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations Planning, Same-day	Medium	The Transmission Operator had a GMD Operating Procedure or Operating Process, but failed to maintain	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include one	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include two or	The Transmission Operator did not have a GMD Operating Procedure or Operating Process

	Operations, Real-time Operations		it.	element in Requirement R3, parts 3.1 through 3.3.	more elements in Requirement R3, parts 3.1 through 3.3.	OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

D. Regional Variances

None.

E. Interpretations

None.

Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The draft standard was posted for a 45-day formal comment period and initial ballot from June 26, 2013 through August 12, 2013. The SAR was posted for informal comment during the same period.

Description of Current Draft

This ~~draft~~ is the ~~first~~second posting of the proposed standard ~~and~~. It is ~~being done in conjunction with the posting of the SAR~~posted for ~~this project~~a 45-day formal comment period and additional ballot.

Anticipated Actions	Anticipated Date
~~30-day Formal Comment Period~~	~~June 2013~~
45-day Formal Comment Period with ~~Parallel Initial~~ Ballot	~~August~~September 2013
~~Successive Ballot (if needed)~~	~~September 2013~~
~~Recirculation~~Final ballot	~~November~~October 2013
BOT adoption	November 2013

Effective Dates

The first day of the first calendar quarter that is six months ~~beyond~~after the date that this standard is approved by an applicable ~~regulatory authorities. In those jurisdictions~~governmental authority or as otherwise provided for in a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months ~~beyond~~after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities.~~ provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03	N/A

Definitions of Terms Used in Standard

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

None

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**

2. **Number:** EOP-010-1

3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   ~~**4.1.2** Balancing Authority with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV~~

   ~~**4.1.3**~~**4.1.2** Transmission Operator with a Transmission Operator Area that includes ~~any~~a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to ~~negatively~~adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and protection system Misoperation, the combination of which ~~can lead to~~may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan ~~to coordinate~~that coordinates GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning~~]~~, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to ~~determine that~~review the GMD Operating Procedures of ~~all~~ Transmission Operators ~~and Balancing Authorities~~ in the Reliability Coordinator Area~~ are coordinated and compatible. ~~.

Rationale and supporting information for Requirement R1: An Operating Plan is implemented by carrying out its stated actions. Coordination is intended to ensure that operating procedures are not in conflict with one another. An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; ~~and~~ evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented ~~such as correspondence with Transmission Operators and Balancing Authorities~~as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. ~~Each Reliability Coordinator shall~~Each Reliability Coordinator shall ~~review its GMD Operating Plan at least once every 36 calendar months from~~disseminate forecasted and current space weather information as specified in ~~the~~ the ~~last effective date.~~ Reliability Coordinator's GMD Operating Plan. ~~*[Violation Risk Factor: Medium]*~~*[Violation Risk Factor: Medium]* ~~*[Time Horizon:*~~*[Time Horizon:* ~~*Long-term Planning,*~~*Same-day* ~~*Operations*~~*Operations* ~~*Planning]*~~*, Real-time Operations]*

M2. ~~Each Reliability Coordinator shall have evidence that it has reviewed its GMD Operating Plan within the timeframe of Requirement R2 such as a dated~~Each Reliability Coordinator shall have evidence such as dated ~~review signature sheet~~operator logs, voice recordings, transcripts, ~~or~~ or ~~revision history.~~electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

R3. Each Transmission Operator ~~and Balancing Authority~~ shall develop, maintain, and implement an Operating ~~Procedures~~Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating ~~Procedures~~Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. ~~The steps~~Steps or tasks ~~for the acquisition and dissemination of~~to receive space weather information ~~to its~~.

3.2. System ~~Operators.~~

~~3.2. The steps or tasks~~Operator actions to be ~~employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan to mitigate the effects~~initiated based on ~~the system from GMD events.~~

~~3.3 The~~ predetermined ~~trigger~~ conditions.

3.3 The conditions for ~~initiating and~~ terminating ~~steps or tasks in~~ the Operating Procedure or Operating Process.

M3. Each Transmission Operator ~~and Balancing Authority~~ shall have a GMD Operating ~~Procedures~~Procedure or Operating Process meeting all the provisions of Requirement R3~~.~~

~~**R4.** Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last~~

Rationale and supporting information for Requirement R2: Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Rationale and supporting information for Requirement R3: An Operating Procedure or Operating Process is implemented by carrying out its stated actions.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

~~effective date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M4**. Each Transmission Operator and Balancing Authority shall have~~; evidence ~~that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4~~ such as a ~~dated~~ review ~~signature sheet~~ or revision history~~.~~

~~**R5.** Each Transmission Operator and Balancing Authority shall have a copy of its GMD~~ to indicate that the GMD Operating Procedure or Operating ~~Procedures in its primary control room and any applicable backup control rooms so that it is available~~Process has been maintained; and evidence to ~~its operating personnel prior to its implementation date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M5**. Each Transmission Operator and Balancing Authority shall have hard copies or electronic copies of its GMD Operating Procedure available for inspection~~show that the Operating Procedure or Operating Process was implemented as ~~stated.~~ called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

~~**R2.** Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M2**. Each Reliability Coordinator shall have evidence that it has reviewed its GMD Operating Plan within the timeframe of Requirement R2 such as a dated review signature sheet or revision history.~~

~~**R4.** Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M4**. Each Transmission Operator and Balancing Authority shall have evidence that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4 such as a dated review signature sheet or revision history.~~

~~**R5.** Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M5**. Each Transmission Operator and Balancing Authority shall have hard copies or electronic copies of its GMD Operating Procedure available for inspection as stated.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator~~,~~ and Transmission Operator ~~and Balancing Authority~~ shall keep data or evidence to show compliance as identified below unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for ~~3~~three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit~~s~~

Self-Certification~~s~~

Spot Check~~ing~~

Compliance ~~Violation Investigations~~Investigation

Self-Reporting

~~Complaints Text~~

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator ~~failed to maintain~~ had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
~~R2~~R2	~~Long-term Planning,~~Same-day ~~Operations~~Operations ~~Planning~~, Real-time Operations	~~Medium~~Medium	~~The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than 39 months, since the effective date.~~ –N/A	~~The Reliability Coordinator reviewed its GMD Operating Plan more than 39 months, but less than 42 months, since the effective date.~~ –N/A	~~The Reliability Coordinator reviewed its GMD Operating Plan more than 42 months since the effective date.~~ –N/A	~~The Reliability Coordinator~~The Reliability Coordinator ~~did not review its~~failed to disseminate forecasted and current space weather information as specified in the Reliability Coordinator's ~~GMD Operating~~

						~~Plan~~GMD Operating Plan.
R3	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The ~~responsible entity~~Transmission Operator had a GMD Operating Procedure or Operating Process, but failed to maintain ~~GMD Operating Procedures~~it.	The ~~responsible entity's~~Transmission Operator's GMD Operating ~~Procedures~~Procedure or Operating Process failed to include one element in Requirement R3, parts 3.1 through 3.3.	The ~~responsible entity's~~Transmission Operator's GMD Operating ~~Procedures~~Procedure or Operating Process failed to include two or more elements in Requirement R3, parts 3.1 through 3.3.	The ~~responsible entity~~Transmission Operator did not have a GMD Operating ~~Procedures~~Procedure or Operating Process OR The ~~responsible entity~~Transmission Operator failed to implement its GMD Operating ~~Procedures~~Procedure or Operating Process.
~~R4~~	~~Long-term Planning, Operations Planning~~	~~Medium~~	~~The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective~~	~~The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 39 months, but less than 42 months, since the last effective date.~~	~~The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 42 months since the last effective date.~~	~~The responsible entity did not review its GMD Operating Procedures and submit them for approval.~~

			~~date.~~			
~~R5~~	~~Long-term Planning, Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not have copies of its GMD Operating Procedures in its primary control room and all backup control rooms if applicable.~~

D. Regional Variances

None.

E. Interpretations

None.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator
Transmission Operator with a Transmission Operator Area that includes any transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

Requirement R2 of EOP-010-1 replaces Requirement R3 of IRO-005-3.1a. IRO-005-4 has been adopted by the NERC Board and filed with FERC in Docket Number RM13-15-000, and will retire Requirement R3 of IRO-005-3.1a:

IRO-005-3.1a, Requirement R3:

> **R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

EOP-010-1 replaces this requirement with the following:

EOP-010-1, Requirement R2:

> **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan**.**

Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, EOP-010-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable governmental authorities or as otherwise made effective pursuant to the laws of applicable to these authorities.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter that is six months beyond the date this standard is adopted by the NERC Board of Trustees or as otherwise made effective pursuant to the laws of applicable governmental authorities.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

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RELIABILITY CORPORATION

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator

~~Balancing Authority with a Balancing Authority Area that includes any transformer with high side terminal voltage greater than 200 kV~~

Transmission Operator with a Transmission Operator Area that includes any transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

Requirement R2 of EOP-010-1 replaces Requirement R3 of IRO-005-3.1a. IRO-005-4 has been adopted by the NERC Board and filed with FERC in Docket Number RM13-15-000, and will retire Requirement R3 of IRO-005-3.1a:

> **IRO-005-3.1a, Requirement R3:**
>
> > **R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

EOP-010-1 replaces this requirement with the following:

> **EOP-010-1, Requirement R2:**
>
> > **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan.

Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, EOP-010-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter~~, six calendar months following applicable regulatory approval.~~ that is six months beyond the date that this standard is approved by applicable governmental authorities or as otherwise made effective pursuant to the laws of applicable to these authorities.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter that is six ~~calendar~~ months ~~following~~beyond the date this standard is adopted by the NERC Board of Trustees ~~approval.~~or as otherwise made effective pursuant to the laws of applicable governmental authorities.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1 (Geomagnetic Disturbance Operations)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET **Friday, October 18, 2013**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

The project page may be accessed by clicking here.

Background Information

The Project 2013-03 Geomagnetic Disturbance (GMD) Mitigation Standard Drafting Team posted an initial draft of the Standard EOP-010-1 (GMD Operations) for comment from June 26 to August 12, 2013. The drafting team has revised the standard based on stakeholder recommendations that the drafting team considered appropriate. The following is a summary of changes the drafting team has made:

- A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in the Reliability Coordinator Area (RCA). IRO-005-3.1a Requirement R3 currently provides this obligation. However, NERC Board has approved IRO-005-4 which would result in retirement of the requirement. The new Requirement R2 in EOP-010-1 will maintain the RCs responsibility for providing space weather forecast information. The implementation plan includes guidance to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010-1 Requirement R2 are effective at the same time.
- In response to stakeholder comments that certain Requirements met Paragraph 81 criteria, administrative requirements for reviewing GMD Operating Plans and Procedures within a 36-month period and for having a copy in the control room were removed.
- Several changes in language were made to improve clarity.
- Applicability:
    - Balancing Authorities (BA) have been removed from the applicable functional entities because there are no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The BA is not expected to initiate specific mitigating actions during a GMD event and would instead respond to the direction of the Transmission Operator (TOP) and Reliability Coordinator (RC). Existing standards provide the required authority for action. A whitepaper with the drafting team's analysis is posted on the project page.

- The applicable TOP has been clarified to include only those that operate power transformers with a high side wye-grounded winding with terminal voltage greater than 200 kV. This applicability statement describes the functional entity in terms of the assets that they operate, which could include non-BES assets. The applicability statement is not intended to define equipment to be protected by the Operating Procedures. The drafting team views 200 kV as the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. A whitepaper with the drafting team's analysis is posted on the project page.

Although some stakeholders suggested that Generator Operators (GOP) be added to the standard as applicable entities, the drafting team maintains that a GOP's Operating Procedures specifically to mitigate the effects of GMD would need to be supported by an equipment-specific study and might require the use of GMD monitoring equipment. Because it is not reasonable to assume that all GOPs have such studies or monitoring equipment, GOPs have not been added to EOP-010-1. Consistent with Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03. Generator Owners (GO) and GOPs will be considered for applicability with stage 2. A whitepaper with the drafting team's analysis supporting the applicability of EOP-010-1 is posted on the project page.

Some stakeholders also commented that the six-month implementation period was too short. The drafting team is sympathetic to the challenge of completing the necessary coordination in a six-month time period. However this implementation period was suggested in FERC Order No. 779 and the drafting team lacks strong justification for a specific longer period.

This posting solicits comment on the revised EOP-010-1 standard. The standard responds to FERC Order No. 779, directing NERC to develop Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014.

Questions on EOP-010-1

1. The drafting team has revised EOP-010-1 in response to stakeholder comments. Changes include removing the BA from applicability, clarifying applicability for TOPs, adding a Requirement for RCs to disseminate space weather information, removal of administrative requirements that do not benefit reliability, and clarifying changes to the language of requirements and measures. Do you agree that the revised standard correctly addresses the Stage 1 directives of Order No. 779 and is acceptable? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

2. Do you agree that the VRFs and VSLs support the reliability objectives of the standard and meet FERC and NERC guidelines? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

3. The Implementation Plan provides conditions for determining when the Requirements in EOP-010-1 become effective in each jurisdition. Do you agree with the Implementation Plan as written? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

4. If you have any other comments for the drafting team to consider that you haven't already mentioned, please provide them here:

Comments:

Standards Authorization Request Form

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

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

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

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

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

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

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

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

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

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

Related SARs	
SAR ID	Explanation

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

Network Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators and Transmission Operators with networks that contain power transformers with high side grounded wye windings above 200 kV. The drafting team concluded that this is the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. This lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature, as explained below.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779.

Justification

Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (115 kV lines are typically less than 15 miles in length), the resulting geomagnetically-induced current (GIC) generated by lines rated less than 200 kV are significantly less than those of higher voltages and are typically ignored in GIC analysis. Conversely, using a voltage threshold higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap by excluding a portion of the network that can be significantly affected by GMD. Results of sensitivity analysis conducted by the drafting team is presented in the appendix. It shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event.

Network Definition Considerations

Key parameters in the definition of a network for assessing GMD impacts are:

- Transformer grounding and core construction
  - Only wye-grounded power transformer windings provide a path for GIC
  - Transformer core construction (e.g, single-phase, three-phase, autotransformer) has an effect on the magnitude of var absorption and generated harmonics. Single-phase transformers are more susceptible to half-cycle saturation due to GIC relative to three-phase 3-leg units; however, the var absorption in 3-legged three-phase core units cannot be neglected.
  - Regardless of core construction, all grounded wye transformers have an effect in the distribution of GIC in the network
- System topology, including geographical orientation
- Resistance values of the elements of the DC network used to evaluate GIC distribution within the network
  - Transmission line resistances per unit length increase as the voltage level decreases (see typical values in Table 1). (With the resistances shown in Table 1, the maximum neutral GIC contributed by a single 230 kV circuit is of the order of 30 A, as opposed to 75 A for a single 345 kV circuit.)

Selection of a network where the cut off is selected on the basis of wye-grounded power transformers with HV terminals > 200 kV

- Almost all peer-reviewed studies on the effects of GIC include networks > 200 kV [1-13].
- When lower voltage levels are included, the effects of including network elements < 200 kV are in most cases minimal [9]. (The Appendix shows an example of the effects of the inclusion/exclusion of the 115 kV network.)
- The absorption of reactive power in a saturated transformer depends on the system operating voltage and GIC. It does not depend on the nameplate rating of the transformer. In the case of single-phase power transformers, var absorption and harmonic generation are very insensitive to air-core reactance [11].

TABLE 1

TYPICAL NETWORK RESISTANCES FOR DIFFERENT VOLTAGE-LEVEL POWER GRIDS IN NORTH AMERICA

System Voltage Levels (kV)	DC Resistances of the Transformers (ohm)	Grounding Resistances of the Substations (ohm)	DC Resistances of the Transmission lines (ohm/km)
230	0.692	0.563	0.072
345	0.356	0.667	0.037
500	0.195	0.125	0.013
735	0.159	0.258	0.011

- Reactive power absorption of a saturated transformer is proportional to its HV voltage rating. Transformers < 200 kV have a relatively lower influence in the reactive power balance of the system (see Figure 1).

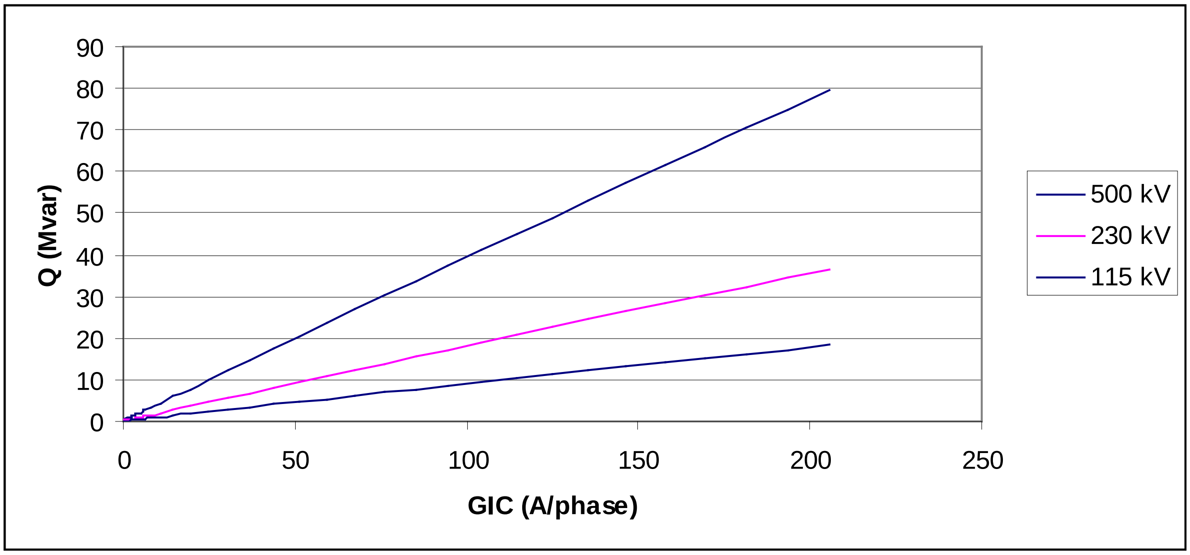

Figure 1: Reactive power absorption of a single-phase transformer vs. GIC

System Impact Considerations

A key element in a GMD event is the absorption of reactive power of high side wye-grounded transformers experiencing half-cycle saturation.

- In many jurisdictions bulk power transmission includes voltages > 200 kV. Tripping a transformer with high side voltage > 200 kV or reconfiguring > 200 kV circuits can impose serious constraints on operating limits; therefore, such operating scenarios must be considered in GMD impact studies.
- Generator step-up transformers are typically situated at electrical end points of the network where GIC tends to be highest. GSUs with high side voltages > 200 kV are not uncommon. On the other hand, GIC injected by circuits < 200 kV is limited because of the higher resistances of GSUs connected to < 200 kV networks
- Autotransformers are often used in networks above > 200 kV. The flow of GIC depends heavily on the relative resistances of various network elements and the geographical orientation of nearby transmission lines [14]. Considering a 500/230 kV autotransformer with one 500 kV and one 230 kV circuit, modelling GIC flow without taking into consideration the 230 kV circuit results in GIC overestimation between 20% and 30%. In a more complex configuration, the estimated GIC ignoring the 230 kV circuits can over or underestimate GIC and the effects of GIC in transformers significantly. The appendix shows an example of this effect.

- From the point of view of GIC distribution in the network, transformer vulnerability is not a consideration. Including only transformers with high side windings > 300 kV would result in unrealistic GIC flow assessments (see Appendix)
- In systems where the bulk transmission voltages are 230 kV and 500 kV, neglecting circuits rated less than 300 kV would misrepresent GIC flows and var absorption, especially because GIC flow-through in 500 kV autotransformers would be neglected (see Appendix).

Appendix

This Appendix describes two examples where:

- The exclusion of 230 kV circuits at a station with 500/230 kV autotransformers cause significant errors in the estimation of GIC effects.
- The inclusion/exclusion of the 161 kV and 115 kV networks in a large utility within the Eastern Interconnect has minimal impact on the estimation of the effects of GIC in the system

Example 1: Exclusion of 230 kV circuits in a 500/230 kV transmission station

The distribution of GIC in a network, for a given geomagnetic latitude and earth structure, depends on a number of factors such as resistances of various circuit elements, induced voltages and network topology. There are times when a complex network topology can lead to non-intuitive results, such as the presence of a series capacitor causing an increase of GIC in a transformer.

To illustrate, consider the topology of the circuits connected to Transmission Station (TS) shown in Fig. A1. If a transmission circuit is sufficiently long it can be represented by a constant current source (since both induced voltage and line resistance are proportional to line length). In the case of a 500 kV circuit, GIC tends to be fairly constant for lengths > 150 km. A simplified representation is shown in Fig A2. The station has several autotransformers which have been lumped into a single equivalent autotransformer. The series capacitor bank is assumed to be out of service (bypassed).

Currents *I1* and *I2* represent the GIC contribution of the 500 kV circuits to the HV bus. Then,

$$I3 = I1 - I2 \qquad \text{(A.1)}$$

where *I3* is the total contribution of the 500 kV circuits to the series winding. The total contribution to the common winding is given by

$$Ig = I3 + I4 + I5 + I6 - I7 \qquad \text{(A.2)}$$

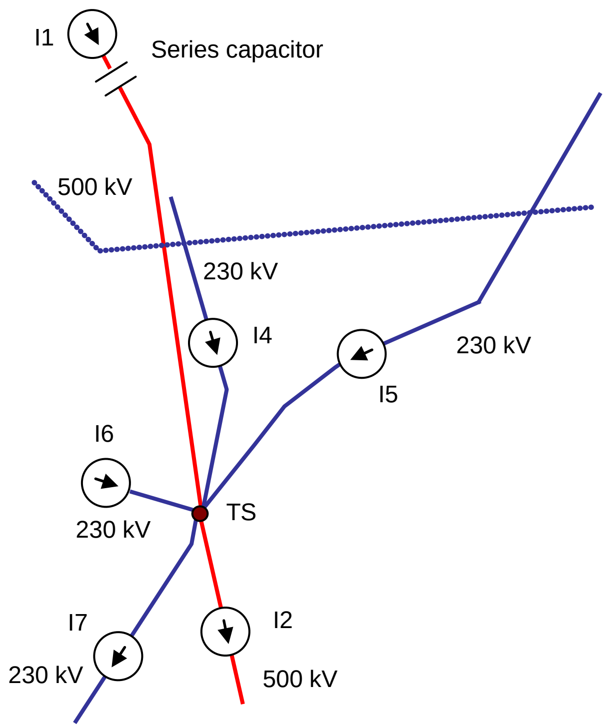

Fig. A1: HV transmission lines connecting to Essa TS.

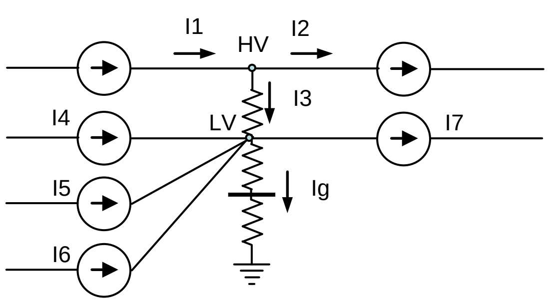

Fig. A2: Circuit representation of induced geoelectric fields and equivalent transformer representation.

Let us assume that the earth can be represented by a laterally-uniform earth model, and that the 500 kV circuits are in the same or similar orientation geographically with the same resistance per unit length, so that the injected GIC I1 and I2 are nearly identical (see Fig. A1). Then I3 will be small or zero and only the 230 kV circuits will contribute to the current in the transformer common winding Ig. If the 230 kV circuits were excluded, (i.e., I4 = I5 = I6 = I7 = 0) then I3 = Ig would be very small and the estimated effects of GIC on the autotransformer would be minimal.

If the 500 kV series capacitor bank in Fig. A1 is placed in service, then I1 = 0 and I2 = I3. The common-winding GIC is now equal to the sum of the GIC contributed by the 230 kV circuits and the remaining 500 kV circuit. Depending on the relative values of the contributions, the net GIC through the transformer may increase or decrease. Simulations show that in the network shown in Figure A1 when the series capacitors are in service, the effective GIC through the transformer increases by a factor of 30. This is not a general result, but rather a consequence of Kirchhoff's current law and a particular system topology.

If the series capacitor bank is in service and the 230 kV circuits are not taken into consideration all the GIC from the remaining 500 kV circuit would flow into the autotransformer and describe a completely different situation from in terms of the saturation of the autotransformer.

The cases described above were simulated with a GIC analysis tool and summarized in Table A1. Note that there are two 500/230 kV autotransformers in service in this simulation.

Table A1: Summary of the Effects of 230 kV Circuits in a Station with Two 500/230 kV Autotransformers

Geoelectric field 5 V/km	230 kV and 500 kV 500 kV Series caps in service	230 kV and 500 kV 500 kV Series caps bypassed	No 230 kV 500 kV Series caps in service	No 230 kV 500 kV Series caps bypassed
Transformer GIC/phase (A/phase)	99.9	2.8	127	5.5
I1 (A/phase)	0	365	0	338
I2 (A/phase)	146.8	334	254	349
Incremental metallic hot spot temperature (C°)	89	1.6	60	7.6
var absorption (Mvar)	128	14	151	12.5
THD (%)	17	2.5	18	2.2

The conclusion from this example is that it is not always possible to make generalizations in a network of relatively complex topology. While it is true that a series capacitor blocks GIC in the transmission line

where it is employed, it does not necessarily reduce GIC in system transformers. Furthermore, not taking into account the effects of the 230 kV circuits in this network would lead to inaccurate conclusions, such as a 33% underestimation of the hot spot temperature rise[1].

Example 2: Effects of the inclusion/exclusion of circuits below 200 kV

A portion of the Eastern Interconnect that contains 500 kV, 230 kV, 161 kV, and 115 kV facilities was modeled using PowerWorld software. When the GIC contribution of the 161 kV and 115 kV circuits was excluded, the effects on the network above 200 kV where found to be minimal. Table A2 summarizes the effects of including/excluding GIC contributions from the 161 kV and 115 kV network assuming a 5 V/km East-West geoelectric field. The differences in the results assuming a North-South geoelectric field are very similar, and are not reproduced in here.

Table A2: GIC Effects on the Network Above 200 kV Assuming an East-West 5 V/km Geoelectric Field

	Including 115 kV	Excluding 115 kV	Difference
Maximum transformer GIC (A/phase)	134.65	133.78	0.6 (%)
Average transformer GIC (A/phase)	13.79	13.46	2.4 (%)
Maximum transformer var absorption (Mvar)	150.3	149.5	0.7 (%)
Average transformer var absorption (Mvar)	7.16	7.08	1.1 (%)
Minimum bus voltage (pu)	0.98204	0.98548	0.4 (%)
Average bus voltage (pu)	1.01858	1.01897	0.04 (%)
Total system var loss due to GIC (Mvar)	3,935	3,801	3.4 (%)

These results are consistent with observations made in peer-reviewed technical publications such as [9].

[1] Hot spot heating was estimated using the methodology described in [15]

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Functional Entity Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators (RC) and Transmission Operators (TOP) with networks above 200 kV. This applicability is consistent with the NERC Functional Model and existing standards where both entities are described as having responsibility and authority for reliable transmission operations within their scope. The drafting team determined that Balancing Authorities (BA) should not be among the applicable functional entities because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The drafting team also determined that Generator Operators (GOP) should not be among the applicable functional entities because any Operating Procedures to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment. Consistent with FERC Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03 and applicability of stage 2 standards will be considered separately.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779. While the applicability of the proposed stage 1 standard is limited to RCs and TOPs, other entities will be considered for stage 2 as outlined in the Standards Authorization Request.

Justification for Applicable Functional Entities

Reliability Coordinator

The RC has responsibility and authority for reliable operation within the Reliability Coordinator Area (RCA). The RC's scope includes a wide-area view with situational awareness of neighboring RCAs. The NERC Functional Model states:

> The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

The RC's authority is codified in IRO-001-1a which states:

> **R3.** The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
>
> **R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

Including the RC as an applicable entity in EOP-010-1 provides the necessary coordination for planning and real-time actions that is envisioned by the Functional Model and addresses Order No. 779 directives to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view.

Transmission Operator

Like the RC, the TOP has responsibility and authority for the reliable operation of the transmission system within a specified area. According to the NERC Functional Model:

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The TOP's authority is established in TOP-001-1a as follows:

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

The 2012 GMD Report contains web links for some TOP Operating Procedures to mitigate the effects of GMD events. Recently the GMD Task Force developed Operating Procedure templates that provide a technical resource for TOPs to use in developing procedures based on industry best practices. Included in the templates are actions that could be employed to mitigate the effects of GMD, such as reduction of equipment loading, increasing reactive reserves, reconfiguration of the system, recalling outages, and Load shedding. The templates also describe indicators of GMD conditions that could be used as trigger conditions for steps or tasks in an entity's Operating Procedures. Detailed study of system and equipment impacts can improve Operating Procedures. However some procedures can be put in place by all TOPs to increase situational awareness and posture the system when a GMD event is forecasted.

Justification for Omitting Functional Entities

Balancing Authority

BAs are responsible for the Real-time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the TOP to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits.

The BA can be expected to address GMD impacts through use of generation. However, the BA would not initiate actions unilaterally during a GMD event and would instead respond to the direction of the TOP

and RC. As such, the independent actions that the BA would take are very limited, if any. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and the concurrence of the TOP and/or RC.

The RC and TOP will be preparing GMD Operating Plans, Operating Processes, and/or Operating Procedures to address steps that each will be taken to address GMD impacts. Some of those steps will require the BA to take action. As outlined above, the requirement for the BA to execute actions at the request of the TOP or RC is clear. Given that the BA would only take action at the request of the TOP or RC and that the required actions would be the same actions BAs take for other sytem events, the SDT concludes that the BA should not be included as an applicable entity in EOP-010-1.

Generator Operator

GOPs are the functional entity that operate generating unit(s) and perform the functions of supplying energy and reliability related services. They may be responsible for operating generator step up (GSU) transformers that connect the generator to the transmission system. Some GSU transformers are susceptible to geomagnetically-induced currents (GICs) during a GMD event, and operating actions are used by some GOPs to mitigate system or equipment impacts.

An effective GOP GMD Operating Procedure to mitigate the effects of GMD would require:

1. GSU transformer study to determine expected GIC on the GSU high side neutral level at their site (GIC/thermal rating study)
2. Ability to monitor GIC at the GSU high voltage wye-grounded winding neutral

Absent the above information, the GOP would not have the technical basis for taking steps on its own and would instead take steps based on the RC or TOP’s Operating Plans, Processes, or Procedures. Therefore, the SDT concludes that GOPs should be excluded as applicable entities in EOP-010-1.

Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure. Furthermore, the RC and TOP will be preparing GMD Operating Plans and Operating Processes or Procedures, respectively. Those will address steps that each will be taking to address GMD impacts, which may include requiring one or more GOPs to take action. Existing standards provide obligations for the GOP to execute actions when requested by the TOP or RC as described above.

Generator Owners (GOs) and GOPs are included in the Project 2013-03 Standards Authorization Request. They will be considered for inclusion in Stage 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. Such mitigation strategies could include the development of Operating Procedures for applicable GOs and GOPs.

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Geomagnetic Disturbance Operating Procedure Template

Transmission Operator

Overview

Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of geomagnetically induced currents (GIC) on system reliability. They also have the merit of being relatively easy to change as new information and understanding concerning this threat becomes available. Operating procedures need to be easily understood by, and provide clear direction to, operating personnel. This is especially true since most operators are unlikely to frequently respond to significant GMD events.

Some actions listed below should only be undertaken if supported by an adequate GIC impact study and/or if adequate monitoring systems are available. Otherwise they can make matters worse. Those actions are indicated by the phrase "if supported by studies".

Determining that a geomagnetic disturbance (GMD) is significant enough to warrant the initiation of special operating procedure(s) depends on the geographical location of the power system/equipment in question coincident with the location of the GMD measurement and forecast. Amount of advance notice obviously factor heavily in what specific actions can and should be taken. Note these are recommended actions; specific actions may vary by system configuration, system design and geographic location of the entity.

Information and Indications

The following are triggers that could be used to initiate operator action:

- External:
    - NOAA Space Weather Prediction Center or other organization issues:
        - Geomagnetic storm Watch (1-3 day lead time)
        - Geomagnetic storm Warning (as early as 15-60 minutes before a storm, and updated as solar storm characteristics change)
        - Geomagnetic storm Alert (current geomagnetic conditions updated as k-index thresholds are crossed)
- Internal:
    - System-wide:
        - Reactive power reserves
        - System voltage/MVAR swings/current harmonics
    - Equipment-level:

- GIC measuring devices
- Abnormal temperature rise (hot-spot) and/or sudden significant gassing (where on-line DGA available) in transformers
- System or equipment relay action (e.g., capacitor bank tripping)

Actions Available to the Operator

The following are possible actions for Transmission Operators based on available lead-time:

Long lead-time (1-3 days in advance, storm possible)

1. Increase situational awareness
    a. Assess readiness of black start generators and cranking paths
    b. Notify field personnel as necessary of the potential need to report to individual substations for on-site monitoring (if not available via SCADA/EMS)
2. Safe system posturing (only if supported by study; allows equipment such as transformers and SVCs to tolerate increase reactive/harmonic loading; reduces transformer operating temperature, allowing additional temperature rise from core saturation; prepares for contingency of possible loss of transmission capacity)
    a. Return outaged equipment to service (especially series capacitors where installed)
    b. Delay planned outages
    c. Remove shunt reactors
    d. Modify protective relay settings based on predetermined harmonic data corresponding to different levels of GIC (provided by transformer manufacturer).

Day-of-event (hours in advance, storm imminent):

1. Increase situational awareness
    a. Monitor reactive reserve
    b. Monitor for unusual voltage, MVAR swings, and/or current harmonics
    c. Monitor for abnormal temperature rise/noise/dissolved gas in transformers[1]
    d. Monitor geomagnetically induced current (GIC[2]) on banks so-equipped[3]
    e. Monitor MVAR loss of all EHV transformers as possible

---

[1] Requires proper instrumentation (e.g., fiber to hot-spot). Note there may be unusual heating in a location other than the normal hot-spot location. Dissolved gas analysis may be available in real-time if the transformer is so-equipped; otherwise, post-event DGA may be performed.

[2] 10 amperes per phase GIC is a good starting point for potential impacts on heavily loaded transformers when actual limits are unknown. Newer transformers may have significantly higher GIC withstand capability if specified at the time of construction. For vulnerable transformers, the OEM can perform analytical withstand studies to better define a particular design's GIC vs. Time withstand capability

[3] Regarding the effects of GIC on transformers, real-time mitigation (after a storm is already in progress) should not be taken based solely on a single indicator (e.g., increased GIC). At least one additional indicator should be monitored to determine if the transformer is actually being adversely affected (e.g., increased MVAR loss, abnormal temperature rise, etc)

   f. Prepare for unplanned capacitor bank/SVC/HVDC tripping[4]
   g. Prepare for possible false SCADA/EMS indications if telecommunications systems are disrupted (e.g., over microwave paths)
2. Safe system posturing (only if supported by study)
   a. Start off-line generation, synchronous condensers
   b. Enter conservative operations with possible reduced transfer limits
   c. Ensure series capacitors are in-service (where installed)

Real-time actions (based on results of day-of-event monitoring):

1. Safe system posturing (only if supported by study)
   a. Selective load shedding[5]
   b. Manually start fans/pumps on selected transformers to increase thermal margin (check that oil temperature is above 50° C as forced oil flow at lower temperatures may cause static electrification)
2. System reconfiguration (only if supported by study)
   a. Remove transformer(s) from service if imminent damage due to overheating (possibly automatic by relaying)
   b. Remove transmission line(s) from service (especially lines most influenced by GMD)

Return to normal operation

This should occur two to four hours after the last observed geomagnetic activity.

Related Documents and Links

2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbance on the Bulk Power System, dated February 2012
http://www.nerc.com/files/2012GMD.pdf

Industry Advisory: Preparing for Geomagnetic Disturbances, dated May 10, 2011
http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf

[4] Consideration should be given to replacing protective relaying (as part of planned GIC mitigation projects) to prevent false tripping of reactive assets due to GIC should be considered. Note that capacitor units have harmonic overload limits that should be observed (see IEEE Std 18).
[5] Giving preference of course to the most critical/sensitive loads (e.g., national security, nuclear fuel storage site, nuclear plant offsite sources, chemical plants, emergency response centers, hospitals, etc)

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

Formal Comment Period: September 4, 2013 – October 18, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: October 9-18, 2013

Now Available

A 45-day formal comment period for **EOP-010-1 - Geomagnetic Disturbance Operations** is now open through **8 p.m. Eastern on Friday, October 18, 2013**.

As a result of comments received, the drafting team has identified the need to make significant changes to the standard. Although Section 4.12 of the NERC Standard Processes Manual indicates that the drafting team is not required to respond in writing to comments from the previous posting when it has identified the need to make significant changes to the standard, the drafting team is providing summary responses to the comments received in order to facilitate stakeholder understanding.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, October 18, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

Additional Ballot and Non-binding Poll Results

Now Available

An additional ballot for **EOP-010-1 – Geomagnetic Disturbance Operations** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Monday, October 21, 2013**.

This standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 77.58% Approval: 88.75%	Quorum: 75.89% Supportive Opinions: 90.04%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

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North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2013-03 GMD Additional Ballot October 2013
Ballot Period:	10/9/2013 - 10/21/2013
Ballot Type:	Additional Ballot
Total # Votes:	308
Total Ballot Pool:	397
Quorum:	**77.58 % The Quorum has been reached**
Weighted Segment Vote:	88.75 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	71	0.899	8	0.101	0	8	18
2 - Segment 2	10	0.7	7	0.7	0	0	0	1	2
3 - Segment 3	91	1	54	0.915	5	0.085	0	11	21
4 - Segment 4	30	1	15	0.789	4	0.211	0	4	7
5 - Segment 5	89	1	49	0.86	8	0.14	0	9	23
6 - Segment 6	54	1	31	0.838	6	0.162	0	3	14
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	6	0.4	3	0.3	1	0.1	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**397**	**7.1**	**240**	**6.301**	**32**	**0.799**	**0**	**36**	**89**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz (AEP))
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)

1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	COMMENT RECEIVED
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell		
1	Transmission Agency of Northern California	Bryan Griess		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Florida Municipal

				Power Agency (FMPA))
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz with American Electric Power)
3	Alabama Power Company	Robert S Moore	Abstain	
3	Ameren Services	Mark Peters	Affirmative	
3	American Public Power Association	Nathan Mitchell	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
				SUPPORTS

3	Kissimmee Utility Authority	Gregory D Woessner	Negative	THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Nebraska Public Power District by Don Schmit.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities	Tim Beyrle		

	Commission			
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Negative	COMMENT RECEIVED
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	

5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	SUPPORTS THIRD PARTY COMMENTS - SERC OC Review Group - (Threshold should be > 300 MW)
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	

5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs		
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA's comments)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's comments)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	

6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Abstain	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Michigan Public Service Commission	Donald J Mazuchowski		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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NERC

Non-Binding Poll
Project 2013-03

Non-binding Poll Results	
Ballot Name:	Project 2013-03 Non-binding Poll GMD October 2013
Ballot Period:	10/9/2013 - 10/21/2013
Total # Votes:	277
Total Ballot Pool:	365
Ballot Results:	75.89% of those who registered to participate provided an opinion or an abstention; 90.04% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	

1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard		

1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Transmission Agency of Northern California	Bryan Griess		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Abstain	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		

2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz from American Electric Power)
3	Alabama Power Company	Robert S Moore	Abstain	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	

3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	

4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of FMPA)
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Negative	COMMENT RECEIVED
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		

5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		

5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs		
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA's Comments)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's comments)

6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (37 Responses)
Name (20 Responses)
Organization (20 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (37 Responses)
Question 1 (27 Responses)
Question 1 Comments (32 Responses)
Question 2 (23 Responses)
Question 2 Comments (32 Responses)
Question 3 (25 Responses)
Question 3 Comments (32 Responses)
Question 4 (22 Responses)
Question 4 Comments (32 Responses)

Group
Florida Municipal Power Agency
Frank Gaffney
Yes
According to the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers connected in a grounded wye configuration. This is the primary reason for FMPA's negative vote. FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. The resistance of 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line. Although FMPA believes the threshold should be raised to

300 kV, we can "live" with a 200 kV threshold if the applicability to 200 kV is to TOPs that operate three single leg core design transformers connected in a grounded wye configuration.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
No
Group
Arizona Public Service Co.
Janet Smith
Yes
Yes
No
The implementation period should be no less than 1 year, 6 months implementation time would cause significant strain and will not allow an effective procedure to be developed.
Yes
Suggest changing R3.2 to as follows: System Operator actions to be initiated based on predetermined conditions, if known to be a susceptible to GMD. During the Webinar, it was pointed out that TOP is not required to have a study or measurement to find the predetermined conditions and most TOP would not know of such conditions existing in their system. The suggested language change would make it clear that they are not required to know the predetermined conditions.
Group
Northeast Power Coordinating Council
Guy Zito

Yes
The Time Horizon brackets for Requirement R1 incorporate four (4) Time Horizons shown as: [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations] It is not clear which Time Horizon goes with what part of Requirement R1. Suggest adding the clarification in a Rationale Box as follows: Development of the GMD Operating Plan is in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan is in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan is in the Same-Day and Real-Time Time Horizons.
Yes
Yes
Yes
The text of the "Effective Dates" section should be consistent with the EOP family of standards to reduce the variance between EOP Standards. Regarding Requirement R1 and its Measure M1, times for completion need to be added. The Violation Severity Levels have to be revised accordingly. The contents of the Rationale Boxes for R1 and R3 as they shown are obvious, and can be removed. In the response to Question 1 above we suggested an addition to the Rationale Box for R1. The Rationale Box for R2 should not repeat wording from R2.
Group
PacifiCorp
Ryan Millard
Yes
Yes
Yes
Yes
Individual
Ayesha Sabouba
Hydro One
Yes

A process for the RC to review the GMD Operating Procedures of TOs in the RCA from the point of view of coordination is needed.
Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
No
While AEP welcomes the removal of the word “coordinate” as an action performed by the RC, the word is now used as something that is done by the Operating Plan. Despite this change, and because the RC is required to implement the Operating Plan, there still appears to be an “implied” obligation where the RC must coordinate. This term remains vague, and more specific text should be used in its place such as “affirm the compatibility of Operating Procedures and Operating Processes among the entities within the Reliability Coordinator Area.” Operating Plans developed by Reliability Coordinators may be quite different from area to area, which may be necessary in some circumstances. However, because AEP serves in multiple Operating Regions, we hope that the various Operating Plans, when feasible, are uniform for the most part. R1 states that the Operating Plan must coordinate GMD Operating Procedures, but makes no mention of the Operating Process as required in R3. Similarly, R1.2 requires a process to review GMD Operating Procedures but again makes no mention of reviewing Operating Processes. We recommend adding “Operating Processes” in R1 and R1.2, so that R1 reads “Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area.” and that R1.2 reads “A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators in the Reliability Coordinator Area.”
No
We do not believe failure to meet R3.3, i.e. failure to terminate the Operating Procedure or Process after a GMD event, justifies a Medium VRF. Instead, a “Low” VRF is recommended.
Yes

The time horizon “Long-term Planning” seems more appropriate for the Stage 2 aspect of this GMD standard, and not for the Stage 1. Please provide carification for how Long-term Planning is to be applied for R1 and R3 as well as justification for doing so. Although this may be ouside the scope of this project team, we encourage NERC to resolve the discrepancies between the definition of Long-term Planning as provided in NERC’s Time Horizon and the definition of “Long-Term Transmission Planning Horizon” in the NERC Glossary of Terms. AEP recognizes the perceived urgency of this project, supports the objective of the proposed standard, and appreciates the efforts of the drafting team. Our negative vote is driven solely by our desire for additional clarity as stated in our comments. AEP foresees voting in the affirmative once the issues and concerns expressed in this response are addressed in future versions of the draft.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst votes in the affirmative because this standard will help to mitigate the effects of geomagnetic disturbance (GMD) events by requiring the Reliability Coordinator to implement Operating Procedures and the Balancing Authorities and Transmission Operators to implement Operating Plans. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 - To be consistent with the language in Requirement R3, ReliabilityFirst believes the term “Operating Process” should be added to Requirement R1. Furthermore, Requirement R1 should include a statement tying it back to the Transmission Operator’s Operating Procedure or Operating Process in Requirement R3. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures [and Operating Processes, as developed in Requirement R3,] within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:…” 2. Consideration for new Requirement R4 - ReliabilityFirst submitted this comment during the last comment period but believes it may have been overlooked (i.e., we believe it was not addressed in the consideration of comments report). ReliabilityFirst recommends including a new Requirement R4 which would require adjacent Reliability Coordinators to share their respected GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators should be aware of each other’s GMD Operating Plans.

Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
Yes
Yes
Because GMD can be a wide area event the TOP efforts should focus on coordinating operations and procedures with the RC. Also, GMD is a high-impact, low-frequency event so overall risk to the TOP should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
Yes
Public Utility District No.1 of Snohomish County agrees in general, however appropriate implementation time should be given so that the Reliability Coordinator ("RC") has the time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions.
Although GMD and Geomagnetically Induced Currents ("GIC") have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufacturers. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on the level of impact a GMD can have on the BES and what level of risk a GMD poses compared to other adverse impact events.
Individual
John Seelke
Public Service Enterprise Group
No
R2 states "Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan." We agree, but in R1 which requires such a plan, there is not requirement related to R2. We believe R1 should have subpart 1.1 rewritten as follows: 1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area WHICH INCLUDE AN ACTIVITY TO DISSEMINATE FORECASTED AND CURRENT SPACE WEATHER INFORMATION.

Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
I believe that either this standard should only apply to the RC or the stage 1 directives should be addressed outside the standards process. Recent GDM events have shown little to no impact on the Bulk Electric System and creating a GDM Operating Plan requirement and auditing process is likely to have little reliability impact other than blindly following the letter of these directives.
No
No
No
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of system topology, including geographical orientation, in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures: “An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures.” Seminole acknowledges that the SDT did not adopt this suggestion during the last comment period for the reason that the SDT did not wish to begin naming criteria that could be utilized in documenting an Operating Plan, i.e., an exhaustive list. However, while reviewing the SDT’s Network Applicability document posted with this Standard, NERC incorporated two out of the three Network Definition Considerations into the Proposed Standard, those two being the wye-grounded power transformer requirement and the lower limit voltage of 200 kV, while not adopting the system topology consideration. Seminole agrees with NERC that this is an important consideration in assessing GMD impacts and believes that this should be incorporated into the Standard in a manner that does not restrict additional considerations. As previously noted, the above suggested language comes directly from the SAR for this project.

Group
NERC Compliance Policy
Connie Lowe
Yes
Yes
Individual
Phil Anderson
Idaho Power
Yes
Yes
Yes
No
Group
Colorado Springs Utilities
Kaleb Brimhall
NA
Yes
• Thank you for your efforts. The standard drafting team has not provided sufficient technical justification for the 200 kV threshold. Utility research indicates that the threshold should begin more around the 300kV threshold.
Yes
Yes
Yes

1. Thank you for all of your work SDT! 2. For the record. We have concern over the fact that action is being required prior to defining the risk? A blind shotgun approach consumes a lot of unnecessary resources, as it is anticipated that there are many entities that will not be at risk to GMDs. We understand that FERC is pushing for action, but think that their push should be founded on established risk.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC Operating Committee (OC)
Individual
Michael Falvo
Independent Electricity System Operator
Yes
(1) We agree with all the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. However, we believe Part 1.2 should be expanded to convey the need for developing recourse. Part 1.2 stipulates that the RC's GMD Operating Plan shall include: 1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area. When a RC's review of the TO's operating procedures finds something lacking, then the recourse to make corrections should be made more clear. We suggest Part 1.2 be revised as follows: 1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area, and direct the Transmission Operators to correct deficiencies, if any. If the SDT accepts this recommendation, please make a mirror change in R3 that will require the TOP to comply with the RC's directive for correcting the deficiencies. (2) R2 as written is unclear on to whom the weather condition is to be provided. We suggest R2 to be clear that the RC is disseminating space weather information to TOPs, as stated in the Background Information in the Comment Form "A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in the Reliability Coordinator Area (RCA). (3) R3 – The term 'Operating Process' is unnecessary and inconsistent with the wording in R1. We suggest to remove "or Operating Process" from R3 in the statement "Each Transmission Operator shall develop, maintain, and implement an Operating Procedure or Operating Process…".
Yes

Yes
Individual
Kathleen Goodman
ISO New England Inc.
Agree
IRC SRC
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC OC Review Group
Individual
Richard
Vine
Agree
The ISO supports the comments submitted by the ISO/RTO Standards Review Committee
Individual
Alice Ireland
Xcel Energy
Yes
We have the following additional comments, but don’t view them as show stoppers. Because R2 specifies that the RC must disseminate space weather information as specified it he RC GMD Op Plan, it would seem logical that there be a sub requirement in R1 that requires the RC has a process to distribute the space weather and list the entities and/or functions for distribution. R3.1 seems unnecessary since R2 requires the RC to disseminate space weather info, presumably the TOPs are included. It isn’t clear what steps or tasks an entity would have to ‘receive’ space weather information.
Yes
none
Individual
Don Schmit

Nebraska Public Power District
Yes
NPPD supports the comments submitted by the Southwest Power Pool. In addition we would like to add this comment: “The drafting team is requiring operating procedures to be in place prior to studying the GMD effects on the TOP system. To determine what effects the GMD will have on the TOP’s system, the studies should be preform first and then the operating procedures developed. The drafting team is requiring generic operating procedures which may or may not address the GMD issues on the TOP’s system. It makes more sense to delay the implementation of the operating procedures until the studies have been performed.”
Group
SERC OC Review Group
Sammy Roberts
Yes
In R1 the requirement calls for the RC to review an “Operating Procedure”. We request the SDT to consider adding “Operating Process” so it is consistent with R3.
Yes
Yes
We would like to thank the SDT for their responses to stakeholder comments. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
SPP Standards Review Group
Robert Rhodes
No
We propose changing the wording in Section 4.1.2 under Applicability to read: Transmission Operator with a Transmission Operator Area that includes a power transformer with a high-side, wye-grounded winding with a terminal voltage greater than 200 kV. This clarifies that the 200 kV winding is the high-side, wye-

grounded winding. We suggest changing the 'the Reliability Coordinator Area' to 'its Reliability Coordinator Area' in R1.2. We suggest replacing 'respective system' with 'Transmission Operator Area' in R3. This language would then parallel that of R1.
Yes
We would prefer to see the VRFs at Low rather than the assigned Medium, but can live with them as proposed.
Yes
The treatment of the Effective Date in the standard appears to address the issue of implementation in the Canadian provinces. Hopefully this will resolve the issue.
Yes
We want to thank the drafting team for taking the time to provide summary responses to help the industry's understanding of the changes even though they didn't have to.
Group
Duke Energy
Colby Bellville
Yes
In R1.2, the requirement calls for the RC to review an "Operating Procedure". Duke Energy recommends adding "Operating Procedure or Operating Process"for consistency with R3.
Yes
Yes
Yes
Duke Energy would like to thank the SDT for their response to stakeholder comments.
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
We agree with most of the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. Nevertheless, we offer the following comments intended to further improve the standard. 1. Certain wording in the proposed R2 introduces

an unclear requirement in R2 and implied requirements in R1. R2 stipulates that the RC shall dissemintate forecasted and current space weather information “as specified in the Reliability Coordinator's GMD Operating Plan”. It is not clear what is it in the GMD Operating Plan that the RC must follow: is it the entities to whom the RC need to disseminate the information, or is it the forecast and current space weather information, or is it the timing for the dissemination, or a combination or all of the above? R1 does not provide this detail. We suggest the SDT to either add the detail in R1, or to remove or reword the phrase “as specified in the Reliability Coordinator’s GMD Operating Plan” to remove the uncertainty and implied requirement. 2. We would also suggest some wording change to R1, which currently stipulates that: R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures within its Reliability Coordinator Area. A plan does not ”coordinate”. Depending on the intent of the requirement – whether it mandates the RC to coordinate the GMD operating procedure or the RC to have a GMD operating plan that contains the coordinated operating procedures, and to more specifically indicate who to coordinate with, a more appropriate wording could be: “Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan to coordinate GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.” Or, the wording could be: “Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that reflects (or covers or stipulates) the coordinated GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.”
Yes
Yes
No
Group
Oklahoma Gas & Electric
Don Hargrove
Yes
The Standard, as written, requires entities to have a plan, but it fails to identify a clear and measurable expected outcome, such as a stated level of reliability performance, a reduction in a specified reliability risk (prevention), or a necessary competency.

Group
Southern Company
Wayne Johnson
Agree
SERC OC
Group
US Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) appreciates the drafting team's decision to require Reliability Coordinators (RCs) to disseminate space weather information rather than requiring each TOP to acquire and disseminate space information.
Yes
Yes
Reclamation appreciates the drafting team's efforts to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010 Requirement R2 are effective at the same time.
Group
ACES Standards Collaborators
Ben Engelby
Yes
1) The draft standard is much improved over the previous version. We thank the drafting team for removing the administrative requirements and removing BA applicability. We also agree that the standard does address the FERC directive. However, we believe there is another option that is as equally effective, is actually more efficient than writing a new standard and eliminates the redundancy that this proposed standard creates. The other option is to rely on existing standards. TOP-001-1a R2 and R8 already require the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. EOP-001-2 R2.2 requires the TOP to "develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system." IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of

information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective. Since these standards requirements are applicable at all times including during GMD events, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements.
No
Because we question the need for the standard at this juncture, we cannot support the VSLs or VRFs. At best, the VRFs should all be low. For a requirement to be assigned a Medium VRF, a single violation of the requirement would have to “directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system” as defined in the Medium VRF definition. A single violation of any of these requirements will not “directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system.” Other standards would have to be violated first. For example, both TOP-002-2.1b R8 and TOP-004-2 R6.1 would have to be violated as well to effect the electrical state, monitoring and control of the bulk electric system. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Other requirements that would have to be violated include EOP-001-2 R2.2 and IRO-014-1 R1.
Yes
While we continue to believe there is another equally efficient and more efficient alternative to development of this standard, the implementation plan is reasonable within the constraints of this standard. However, we have concerns that the second phase of this project may alter the work done in phase one, including modifications to the implementation plan and the entities that could be subject to compliance with this standard.
Yes
(1) Requirement R2 should be made a sub-part of Requirement R1 to avoid double jeopardy and because it is essentially a constraint on the Operating Plan. If a registered entity fails to write an Operating Plan, it will also fail to include in its Operating Plan the method for disseminating space weather. Since violations are assessed per requirement, one compliance failure could result in two compliance violations of R2 and R3. Thus, if R2 is written as a sub-part of R1, failure develop an Operating Plan will be assessed as a single violation of the combined requirement. Furthermore, R2 essentially is a requirement for what should be

contained in the Operating Plan and, therefore, more appropriately belongs as a sub-part of R1. (2) Part 3.1 in R3 is unnecessary and redundant with other requirements. R2 already compels the RC to disseminate space weather information. Because the RC is a higher authority than the TOP, the TOP is already required to receive the information as a result by implication. The RC's authority is documented in IRO-001-1a R3 and R8. The RC may issue directives to the TOP to follow its GMD Operating Procedure or Process while disseminating information about severe space weather. Furthermore, NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. Codifying a process that is already in place and works effectively only perpetuates the existing compliance model that places too much emphasis on documentation and not enough on reliability. (3) The SAR should be modified to indicate that Stage 1 will require registered entities to develop and implement Operating Processes and Operating Plans in addition to Operating Procedures. The SAR only references the development and implementation of Operating Procedures which is not consistent with the standard that includes Operating Plans and Operating Processes. (4) We believe the literal meaning of the language in R3 Part 3.3 is not what is intended by the drafting team. As written, the language could be read to literally mean that the Operating Process or Operating Procedure must include language for retiring the Operating Process or Procedure. The problem is with the use of "terminate the Operating Procedure or Operating Process." Terminate means to come to an end. Thus, terminating the Operating Procedure or Operating Process which are documents means to end the document. Obviously, the purpose is to terminate the use of the Operating Procedure or Operating Process when the GMD event has ended. We suggest using the language from the SAR for R3 Part 3.3 as it is clearer and has a more exact meaning of what is intended. The language in the SAR is: "Criteria for discontinuing the use of Operating Procedures at the conclusion of a GMD event." (5) The Long-term Planning Time Horizon for R1 and R3 should be removed. The functional entities to which the standard applies are not planning entities per the functional model and have no long-term planning responsibilities. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions." An operating plan contains operating procedures and processes which are applied in real-time operations. (6) We are concerned that implementation of an operating procedure

for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will satisfy this required coordination. (7) The white paper supporting functional entity applicability should be modified. On page three, the last sentence just before the “Justification for Omitting Functional Entities” section is inconsistent with the standard. It states that “some procedures can be put in place by all TOPs.” The standard limits the procedures to only TOPs with a transformer with a high-side wye-grounded winding greater than 200 kV. Please modify the sentence in the whitepaper for consistency with the standard. (8) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extreme GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southernmost entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies as documented in our responses to other questions. (9) Thank you for the opportunity to comment.
Individual
Cheryl Moseley
Electric Reliability of Texas, Inc.
Yes
ERCOT generally supports the SDT's efforts in developing the draft GMD standard and believes it is on the right track. However, the SDT should consider the following comments in the development of future versions. Most of the requirements seem to be concentrating upon the administration of “having procedures”. The standard should say “what” is required, while minimizing the

required administration activities. 1) Applicability Section The SDT should consider the role of GOPs in the standard. The standard in both its initial and revised form does not address the GOP function. GOPs may have GMD operating plans in place. As the whitepaper on applicable functions noted - “Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure.” Given that generators may have GMD procedures in place, the standard should reflect those procedures on a stand alone basis and as inputs into the larger operational GMD procedures. The failure to consider those plans in developing and coordinating the broader scope operational plans would create a disconnect between core operational roles. Such disconnects could undermine the effective and efficient management of GMD events potentially creating an undesirable reliability impact on the interconnection. Accordingly, the SDT should consider revisions to include the GOP function to ensure generator GMD procedures are considered and reflected in the larger scope GMD operational procedures. These plans should be coordinated with the relevant TOP and RC plans in a coordinated manner that is ultimately overseen by the RC, as proposed in the standard. 2) Requirement 1.2 The revised standard removes the coordination/compatibility determination role of the RC. It seems the RC should be performing these roles to ensure effective and efficient operations in the context of a GMD event. It is not clear that a simple “review” role is adequate to achieve that outcome. The SDT should reconsider whether the RC should have the ability/authority to address any potential conflicts in plans pursuant to a coordination/compatibility determination role. If the revision was intended to simply be a “clean-up” edit, and that the coordination role is adequately covered in the R1 coordination role, R1 should reference R 1.2, so it is clear that the plans referenced in R1 are defined in terms of the specific functional entity referenced in R1.2. 3) Measure 1 The revisions to M1 includes language that calls for evidence related to implementation to be that which demonstrates the entity performed the action "as called for in the GMD Plan...".While ERCOT understands the value of linking implementation evidence to the plan, the way it is drafted it could be interpreted very rigidly such that any operational deviation from the plan would be a violation. Obviously if you have a plan it should be used, but neither the standard nor the measure should be so rigid that if the operators cannot deviate from the plan if necessary based upon unintended circumstances without the risk of noncompliance with this requirement - entities should be able to take actions outside the four corners of the plan if necessary, and the standard and compliance measures should clearly accommodate such actions to avoid unintended consequences where the best operational actions are not taken because entities do not want to risk noncompliance. 4) Requirement 2 Requirement 2 mandates that the RC share forecasted and current space weather information in accordance with its plan. As an initial matter, this implicitly requires RCs to have forecasted and current space weather information in our plans even though the substantive requirements related to the plan in R1 don't require that. This creates ambiguity in terms of whether that is a substantive obligation for the plan. For example, can an RC not have this in their plan, and, if so, does that make that requirement inapplicable in an audit? Another potential ambiguity related to this requirement is that there is no direction in terms of the entities the RC is required to disseminate this information to under the requirement. ERCOT understands the standard leaves this to the RC plan, but again, does that mean the RC does not have to have this in its plan? If this obligation is retained, the scope should be aligned with the functional entities in the standard that have GMD procedural roles (currently just TOPs – although as noted ERCOT questions whether GOPs need to be included in the standard). Also, if this is going to be a plan requirement that should be explicit. To make it clear, it should be established as a substantive component of the plan as part of R1. However, ERCOT does not support this as a substantive requirement. The standard should dictate the substance of functional entity plans. ERCOT also questions the need for the RC to disseminate that information. The information can be obtained by other functional entities independent of RC dissemination, and that obligation, if the SDT elects to require entities to obtain this information, should be assigned to those entities. As drafted, this unnecessarily creates an opportunity for RC non-compliance with what is really administrative obligation i.e. distributing information that can be obtained independent of the RC. To the extent there is an inconsistency risk in terms of the sources/substance of this information, that risk could be managed by the RC coordination role. In addition to the above issues, the requirement is otherwise vague and ambiguous in terms of the scope of the information disseminated. For example, what is the timing for the dissemination? Again, the draft language leaves this to the RC plan, but as discussed, it is not clear if the RC has to have anything related to this, and if it does not, what the impact of that would be in an audit. If this implicitly requires the RC to have this process in its plan, the issue is what is the scope for all aspects – e.g. audience, timing, etc.? Granted the way it is drafted the RC has complete discretion, but there is a concern whether that discretion will be respected by the ERO in the exercise of its CMEP function. To mitigate the potential issues with this requirement, ERCOT believes it should be removed because the standard should require a plan, but should not dictate the substantive components of the plan. Alternatively the standard should be revised to make the obligations explicit and clear with respect to what is required – e.g. R 3.1 makes it clear that TOPs are required to have a process to obtain space weather information. 5) Requirement 3 Related to the above comments on R2, R3 requires TOPs to get space weather info. Given this independent obligation, why does the RC have an obligation to disseminate that info? As discussed, it is unnecessary and creates unnecessary compliance risk. 6) Requirements 3.2 and 3.3 As drafted, these requirements seem too prescriptive. While it is reasonable that a plan establishes actions relative to specific conditions. However, the language should be clear that these are recommended actions, but

are illustrative and non-exclusive. Functional entities should have the flexibility necessary to take actions outside of the plan if operating conditions change and counsel for operating actions outside of the four corners of the plan. 7) Measure 3 Similar to the above comment on Measure 1, as drafted, Measure 3 could be interpreted in a manner that is too prescriptive and limiting, which could create the risk of undermining effective operations by limiting operator actions to the four corners of the plan or risk noncompliance risk. This would undermine the operational flexibility necessary to act outside of the plan if system conditions warranted such actions without risking violation of the requirement.
Yes
Yes
Group
Bonneville Power Administration
Jamison Dye
Yes
Yes
Yes
Yes
BPA recommends the drafting team change the language of the first sentence of R3, from “Each Transmission Operator shall…or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system.” To “Each Transmission Operator shall…or Operating Process intended to mitigate the effects of GMD events on the reliable operation of its respective system.”
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
Yes
Yes

Yes
Tri-State is still concerned with the Standard Drafting Team’s decision setting the limit of applicable transformers from >200kV versus >300kV. This critical decision will have significant cost and time ramifications on the industry. The workload for Tri-State will increase nearly five-fold based on the amount of transformers that fall into the 200-300kV range. We appreciate the work that the volunteer task force has accomplished in helping to prepare the NERC “Network Applicability” paper, but Tri-State believes such a critical decision in setting the limit should be based on more extensive knowledge. The “Network Applicability” justification for including 200kV circuits is only based on an analysis of a small simulated network consisting of two 500/230kV autotransformers with only a few lines running into and out of that station. That analysis, summarized in Table A1 (pg. 7), predicts a decrease of GIC from 5.5 to 2.8 Amps if the 230kV elements are included. The study also estimates an increase in var absorption from 12.5 to 14 Mvar if the 230kV elements are included. Tri-State suggests that these slight variances are well within the error range in the overall assumptions for the many parameters used to predict GIC itself. Parameters such as the line induced kV/km, the magnitude and duration of solar events, the deep earth soils geology, accuracy of the transformer models, ground grid resistance (which may vary season to season), etc. Our suggestion is to give the NERC task force increased time to do research and in the meantime adopt a criteria of detailed analysis of >300kV with a 10% safety factor added for the possible <300kV impact.
Group
Foundation for Resilient Societies
William R. Harris
No
Question 1: Our Foundation's Case Study on Maine and ISO New England's capacity to mitigate a severe solar geomagnetic storm (March 2013 - found on website www.resilientsocieties.org) reaffirmed our prior understanding that the Regional Coordinators (in this case ISO-New England) cannot adequately coordinate "operating procedures" to mitigate a severe GMD event without concurrent jurisdiction over Balancing Authorities (BAs) and Generator Operators (GOs). In a severe solar storm, the combination of generation reserves together with demand response reserves may not enable Regional Coordinators (RCs) to balance loads without active preparation and support of balancing authorities. For ISO-New England that would include Canadian resources and balancing operators beyond the authority and scope of FERC Order No. 779. In effect, the various balancing (BAL) standards do not include standards for emergency hydroelectric generation or protection of equipment, such as series capacitors and static VAR compensators (SVC), necessary to maintain voltage stability for power imported from Canada. Without power imported from Balancing Authorities outside of ISO-

New England, which also may be at risk of concurrent Geomagnetically-Induced Current (GIC), reactive power consumption, and adverse harmonics, the New England region is more likely to be at risk of prolonged electric grid blackout. The rationale of NERC's drafting team for excluding Balancing Authorities from participation as responsible entities to fulfill "operating procedures" is stated in NERC's "Functional Entity Applicability" document, which states: "… Balancing Authorities (BA) should not be among the applicable functional elements because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events." To the contrary, as GIC equipment monitors are already deployed within some Balancing Authorities, BA's need to assess the performance and GMD-related deterioration of networks during the moderate solar geomagnetic storms in coming years. Balancing Authorities may benefit from modeling balancing options under degraded conditions, such as the loss of a key Static VAR Compensator. There are interplays between selection of equipment options, and selection of balancing strategies to "operate through" moderate level solar storms. Further, commercially available GIC monitors now provide "operating procedure" choices for their programming. At what level should different alarms be set, and to which entity should these alarms be reported? BAs have a "need to know" and critical roles to play, in both advising about equipment upgrades and in making best use of, or de-energizing as needed equipment that impacts the ability to balance loads before, during and after a GMD event. For further information on GIC monitors that are now available, see the Foundation Comments of October 15, 2013 in Maine PUC Docket 2013-00415. Moreover, if the Balancing Authorities are full-time partners in "operating procedures" to be coordinated by the RCs, it is more likely that additional GIC monitors will be installed at key locations, and critical equipment such as SVCs, Extra High Voltage (EHV) transformers, and generators will be protected from tripping or permanent damage. Also, power transmission over High Voltage Direct Current (HVDC) ties that are vulnerable to tripping from GIC will be better planned and protected. Already in New England, the Phase II HVDC tie from Canada has tripped off during a solar storm. A second concern of our Foundation relates to the arbitrary limitation of equipment to be subject to "operating procedures" to those portions of utility networks with high-side voltage of 200 kV or higher. We understand that the lower voltage transformers have higher resistance; hence they are generally less susceptible to GIC entering the bulk power system. But there are so many more transformers under 200 kV--roughly double the total transmission mileage in the U.S. transmission infrastructure--and so many more opportunities for "GIC leakage" into the EHV transmission networks. It appears imprudent to exclude transformers in the 100 kV to 200 kV range from "operating procedures." PowerWorld has estimated that less than 60% of total MVAR enters the bulk power system through transformers at 230 kV or higher, in both New England and in Michigan. Other regions that have not been adequately modeled to date may also incur high "GIC leakage" from transformers with high-end voltage under 200 kV. Transformers supplying these additional MVARs may experience transmission congestion, adverse effects of harmonics through overheating and equipment vibration, and risks of equipment damage or total loss. The economics of "operating procedures" may well demonstrate benefits of some combination of equipment installation and operating procedures to reduce the rate of "GIC leakage" into the bulk power system via transmission sub-systems operating below 200 kV. NERC has not done the financial analysis mandated by FERC Order No. 779, so NERC should not prematurely exclude these grid pathways subject to GMD-induced instability, unreliability, and reduced capacity utilization. It is also notable that much of the specialized equipment designed to provide reactive power or to stabilize voltages within design tolerances operate below 200 kV. Is this equipment to be excluded from protective "operating procedures" under Proposed NERC Standard EOP-010-1? Siemens, for example, identifies many Static VAR Compensators operating at less than 200 kV. CenterPoint's Crosby SVC (IOC 2008) operates at 138 kV. Brushy Hill (1986, Canada) operates at 138 kV. Entergy's Porter SVC in Texas (IOC 2005) operates at 138 kV. CenterPoint Energy's Bellaire (IOC 2008) operates at 138 kV; Exelon's 2 SVCs at Elmhurst operate at 138 kV. Entergy's Prospects Heights SVC near Chicago has 2 SVCs at 138 kV. Northeast's Glenbrook, CT STATCOM operates at 115 kV. In “Appendix 2, Detailed Summary of Power System Impacts from March 13-14, 1989 Geomagnetic Superstorm” of “Meta-R-319, Geomagnetic Storms and Their Impacts on the U.S. Power Grid” by John Kappenman (January 2010, Oak Ridge National Laboratory), a table of system impacts on Page A2-2 shows no less than 10 GIC impacts on equipment operating at a base voltage of less than 200 kV. This is real -world data during a moderate solar storm. In contrast, NERC offers only theorizing in its document, “Network Applicability, Project 2013-03 (Geomagnetic Disturbance Mitigation), EOP-010-1 (Geomagnetic Disturbance Operations), Summary Determination” that networks operating at less than 200 kV would not be affected by GIC. Real world data should trump the technical speculation of NERC. Networks operating at less 200 kV (and over 100 kV) are part of the Bulk Power System and should be included in standards for GMD mitigation. Increasingly, the Bulk Power System is connected to wind power generation, with many wind power systems at ocean boundaries that may import above-average GIC. Wind power systems are generally stepped up to less than 200 kV. Wind power transmission systems are increasingly outfitted with GIC monitors. So, if these facilities are excluded from "operating procedures," will that mean that the near-real-time GIC data now available to wind power operators will not be shared with the RCs? It is notable that in the Maine PUC Docket 2013-00415, with documents retrievable via the Internet, John Kappenman of Storm Analysis Consultants reported in October 2013 that, depending upon the orientation of a solar storm, the single GIC monitor at Chester Maine might report little or no GIC, even in a large solar storm. This is the only near-real-time GIC data received by ISO-New England, the relevant RC. Why would NERC seek to exclude GIC monitors at wind generation-transmission interconnections below 200 kV from "operating procedure" management by the Regional Coordinators? This would appear to be imprudent and is likely to result in needless risks to bulk power system reliability. In FERC Order No. 777, 142 FERC Para 61,208, issued on March 31, 2013, FERC provided a rationale for extending a reliability standard below 200 kV voltages under circumstances where the assets under consideration "are critical to reliability." See FERC Order No. 777 at p. 23, in Docket RM12-4-000. All of the SVCs, STATCOMs, series capacitors, and prospective dynamic VAR compensators with voltage under 200 kV should be considered as equipment "critical to reliability" for purposes of GMD operating procedures. Finally, our Foundation is alarmed that Generator Operators are now excluded from "operating procedure" jurisdiction in the proposed standard. Why? The NERC Drafting Team determined “that Generator Operators should not be among the applicable functional entities because any operating procedure to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment.” We find these rationales to be implausible. Generator Operators have, for more than a decade, utilized formulae provided (by ABB and other vendors) to down-power generation, hence loads on unprotected EHV transformers. There is operating experience with these “down-powering” practices that need to be shared as “best practices” or unacceptable practices. Those Generator Operators that already have installed GIC monitors, working with regional models, have already produced estimated of field voltages that will or will not collapse regional transmission networks. It would be imprudent to wait until every Generator Operators has GIC monitors at every GSU transformer to develop “operating procedures” that can protect critical equipment using cost-effective strategies. Another reason to bring Generator Operators into “operating procedure” practices as soon as possible is to help educate Generator Operators to understand the practical limits of “operating procedures” for Generator Operators with equipment running at “GIC hotspots.” Neutral ground blocking devices not only eliminate virtually all GICs entering GSU transformer, but also reduce vulnerabilities of other GSU transformers that are unprotected within regional networks. The sooner executives of Generator Operators learn whether they will benefit from hardware protecting investments, the better. See the Foundation’s reproduction of a NOAA (Denver) initiative to display the frequency of half-cycle solar GMD events for the period 1958-2007 (Figure 20), indicating an above average risk in the years following solar maxima. The last solar maximum occurred in September 2013. See the Foundation Reply Comment of October 15, 2013 in Maine PUC Docket 2013-00415. FERC’s Order No. 779 seeks expedited protection of the bulk power system, not endless delays of needed protections. Many Generator Operators own and operate GSU transformers that at risk for damage due to GICs entering their GSU transformers and the bulk power system. Some Generator Operators, e.g. NextEra, have spun-off subsidiaries that can qualify their EHV transformers for OATTS cost-recovery by transferring ownership

into a closely held transmission company. In either case, Generator Operators are key players in determining whether to downpower during a space weather-warning period. Many Generator Operators are also aware that the harmonics from GICs that enter their systems cause both overheating and vibrational effects on other equipment such as: generator stators, stator cooling pipes, and generator turbines. To exclude Generation Operators from "operating procedures" appears unfounded and a possible aggravating factor in a severe solar geomagnetic storm. Lastly, NERC needs to address what can be done to protect high-cost,long-replacement-time equipment during a severe solar storm, such as the New York Railroad storm of May 1921. Will the Nuclear Regulatory Commission preemptively order the de-energizing of all nuclear generating facilities and associated GSU transformers? Should the President order the de-energizing of all unprotected GSU transformers, including those without neutral ground blocking or designs projected to survive impending GMD events? If so, how will the Generator Operators protect their equipment, train personnel to validate and authenticate de-energization orders, and plan for optimal "black start" procedures? Excluding Generation Operators from the jurisdictional scope of "operating procedures" appears to be based on the convenient but false assumption that the only solar geomagnetic storms for which electric utilities need prepare are those of moderate strength and short duration. We cannot in good conscience vote "yes" for a proposed standard for "operating procedures" that excludes Balancing Authorities, excludes Generator Operators, excludes critical equipment operating at under 200 kV, and excludes operators of GIC monitoring equipment from a mandate to share safety-related information in near-real time. NERC and the electric utility industry can achieve more effective standards. If this standard is approved by NERC as proposed, FERC should require key modifications in its review process.
Yes
Yes
Yes
For further background information on the Foundation's support of wider jurisdiction for coordinated "operating procedures" see our March 2013 case study of Maine and ISO-New England in a solar geomagnetic storm, found at www.resilientsocieties.org and the Foundation's comments responsive to queries by the Maine Public Utilities Commission, in MPUC Docket 2013-00415 (Oct 4, 2013), and our Supplemental and Reply Comments in that same Docket (October 15, 2013).
Individual
Jen Fiegel

Oncor Electric Delivery Company LLC
Yes
Yes
No
The Implementation Plan timeline calls for implementation 6 months from the standard approval or on the first day following the retirement of IRO-005-3.1a. This timeline does not provide sufficient time to create the necessary procedures or processes and train necessary personnel to those processes and procedures. The preferable timeline would be for implementation 12 months from the standard approval or on the first day following the retirement of IRO-005-3.1a, whichever is later.
No
Individual
Rich Salgo
NV Energy
Yes
Yes
Individual
Robert B Stevens
CPS Energy
No
I beleive this standard should be developed regionally, not at a national level.
No
No
Implementation should be at the regional level
No

Consideration of Comments

Project 2013-03 Geomagnetic Disturbance Monitoring

The Project 2013-03 Drafting Team thanks all commenters who submitted comments on the revised draft stage 1 Standard (EOP-010-1). Project 2013-03 will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading in the Bulk-Power System caused by geomagnetic disturbances (GMD) in two stages as directed by the Federal Energy Regulatory Commission (FERC or the Commission)in Order No. 779 (*Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013)(Order No. 779):

1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures with predetermined and actionable steps to take prior to and during GMD events which take into account entity-specific factors that can impact the severity of GMD events in the local area.

2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. The Stage 2 standard(s) must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts. If the assessments identify potential impacts from benchmark GMD events, the standard(s) will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of benchmark GMD events.

The standard was posted for a 45-day formal comment period from September 4, 2013 through October 21, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 37 sets of responses, including comments from approximately 120 individuals from approximately 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the project page.

Summary Consideration:

The drafting team has reviewed all comments and made the following non-substantive changes to incorporate stakeholder recommendations:

- Section 5 (Background): Capitalized "Protection System" because it is defined in the NERC Glossary of Terms.

- Requirement R1: Revised the requirement to include the term Operating Process in R1 and R1 part 1.2 and changed language to be consistent with Requirement R3. The revised requirement with highlighted changes is as follows:

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within ~~the~~ its Reliability Coordinator Area.

- **Measure M1**: Inserted the word "current" to conform to NERC guidelines for writing Measures to support this type of Requirement. The revised measure with highlighted change is as follows:

M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

- **Requirement R2**: Clarified that the Reliability Coordinator shall disseminate forecasted and current space weather information *to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan*. The revised requirement with highlighted change is as follows:

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients ~~as specified~~ in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

- **Requirement R3**: Inserted the word GMD, so that the phrase "GMD Operating Procedure or Operating Process" would be consistent with Requirement R1. The revised requirement is as follows:

R3. Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating

Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

- **Implementation Plan.** A clarifying change was made to the Implementation Plan to conform to the effective date language in the standard, which was changed in the prior draft in response to concerns raised by Canadian entities.

A summary response to each comment follows each question. Please note that because common issues were grouped together in the summaries, an individual's comment may have been addressed in the summary for a question that is different from the question in which they submitted the comment; the drafting team encourages reviewers to read all summary responses.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6. Randy Hahn	Ocala Utility Services	FRCC	3
7. Stanley Rzad	Keys Energy Services	FRCC	3

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1

3.	Group	Connie Lowe	NERC Compliance Policy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
Additional Member		**Additional Organization**	**Region** / **Segment Selection**										
1. Michael Crowley		Dominion	SERC / 1, 3, 5, 6										
2. Mike Garton		Dominion	NPCC / 5, 6										
3. Louis Slade		Dominion	RFC / 5, 6										
4. Randi Heise		Dominion	MRO / 5, 6										
4.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sammy Roberts	SERC OC Review Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. James Case	Entergy	SERC	1, 3, 6
2. William Berry	OMU	SERC	3
3. Gerald Beckerle	Ameren	SERC	1, 3
4. Gary Kobet	TVA	SERC	1, 3, 5, 6
5. Michael Lowman	Duke Energy	SERC	1, 3, 5, 6
6. Terry Bilke	MISO	SERC	2
7. Phil D'Antonio	PJM Interconnection	SERC	2
8. Patrick McGovern	Georgia Transmission Corporation	SERC	1
9. Marsha Morgan	Southern Company	SERC	1, 5

Additional Member	Additional Organization	Region	Segment Selection
10. Tom Pruitt	Duke Energy	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Robert Rhodes	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Kevin Frick	Westar Energy	SPP	1, 3, 5, 6
2. Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
3. Michael Herzog	Omaha Public Power District	MRO	1, 3, 5
4. Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6. Richard Kalina	Omaha Public Power District	MRO	1, 3, 5
7. Dong-Hyeon Kim	Burns & McDonnell	NA - Not Applicable	NA
8. Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
9. Jeff Knottek	City Utilities of Springfield	SPP	1, 4
10. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
11. Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
12. James Nail	City of Independence, MO	SPP	3
13. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
14. Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
15. Scott Williams	City Utilities of Springfield	SPP	1, 4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Colby Bellville	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
1. Kathleen Goodman	ISO-NE	NPCC	2
2. Charles Yeung	SPP	SPP	2
3. Ali Miremadi	CAISO	WECC	2
4. Terry Bilke	MISO	MRO	2
5. Al DiCaprio	PJM	RFC	2
6. Cheryl Moseley	ERCOT	ERCOT	2
7. Ben Li	IESO	NPCC	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Don Hargrove	Oklahoma Gas & Electric	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Terri Pyle	OG&E	SPP	1
2. Leo Staples	OG&E	SPP	5
3. Jerry Nottnagel	OG&E	SPP	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Ben Engelby	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
2. John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
3. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
4. Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
5. Megan Wagner	Sunflower Electric Power Corporation	SPP	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dan Goodrich	Technical Operations	WECC	1
2. Ran Xu	Technical Operations	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Individual	Janet Smith	Arizona Public Service Co.	X		X		X	X				
13.	Individual	Ryan Millard	PacifiCorp					X	X				
14.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
15.	Individual	Wayne Johnson	Southern Company	X		X		X	X				
16.	Individual	Erika Doot	US Bureau of Reclamation	X				X					
17.	Individual	William R. Harris	Foundation for Resilient Societies								X		
18.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
19.	Individual	Ayesha Sabouba	Hydro One			X							
20.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
21.	Individual	Anthony Jablonski	ReliabilityFirst										X
22.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	
23.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
24.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
25.	Individual	Bret Galbraith	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
26.	Individual	Phil Anderson	Idaho Power	X									
27.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
28.	Individual	Michael Falvo	Independent Electricity System Operator		X								
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Richard Vine	California ISO		X								
31.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
32.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
33.	Individual	Cheryl Moseley	Electric Reliability of Texas, Inc.		X								
34.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Jen Fiegel	Oncor Electric Delivery Company LLC	X									
36.	Individual	Rich Salgo	NV Energy	X		X		X					
37.	Individual	Robert B Stevens	CPS Energy					X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
ISO New England Inc.	IRC SRC
Colorado Springs Utilities	NA
Southern Company	SERC OC
Associated Electric Cooperative, Inc. - JRO00088	SERC OC Review Group
South Carolina Electric and Gas	SERC Operating Committee (OC)
California ISO	The ISO supports the comments submitted by the ISO/RTO Standards Review Committee

1. **The drafting team has revised EOP-010-1 in response to stakeholder comments. Changes include removing the BA from applicability, clarifying applicability for TOPs, adding a Requirement for RCs to disseminate space weather information, removal of administrative requirements that do not benefit reliability, and clarifying changes to the language of requirements and measures. Do you agree that the revised standard correctly addresses the Stage 1 directives of Order No. 779 and is acceptable? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on the revised EOP-010-1. All comments have been reviewed and changes that the drafting team considers appropriate were incorporated into a subsequent revision. A summary of comments and the drafting team's response is provided:

- **Consistent language between Requirement R1 and Requirement R3 in describing the required operating measures as "Operating Procedures or Operating Processes." Commenters recommended that Requirement R1 and Requirement R1 part 1.2 include language that matches Requirement R3.** The drafting team has made this clarifying change in the final revision.
- **Unclear or implied requirements for the Reliability Coordinator to include space weather information in the GMD Operating Plan. Some commenters stated that the requirement was unclear; some recommended that the requirement specifically state what information should be disseminated or what recipients it should be disseminated to. Some commenters did not believe the requirement was necessary.** The drafting team's intent with Requirement R2 is to maintain the Reliability Coordinator's existing obligation to disseminate space weather information as specified in IR0-005-3.1a Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. To clarify this intent, the final version of EOP-010-1 Requirement R2 states that the Reliability Coordinator will disseminate space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. The drafting team believes Requirement R1 and Requirement R2 provide the Reliability Coordinator with appropriate flexibility to tailor its GMD Operating Plan to promote consistent awareness of space weather information in the Reliability Coordinator Area.
- **Requirements for the RC to coordinate GMD Operating Procedures and Operating Processes. Commenters stated that R1 needed to be more specific about how coordination should occur. Some commenters stated that Requirement R1 should be expanded to specifically address recourse when the RC required changes to a TOPs Operating Procedures or Operating Processes after review.** The drafting team believes that Requirement R1 as written describes the essential elements to assure coordination and is consistent with the roles described in the NERC Functional Model. The drafting team did not believe that the suggestion to replace "coordinate" with "affirm the compatibility of" in Requirement R1 improved clarity. C*oordination* is intended to ensure that Operating Procedures within a Reliability Coordinator Area are not in conflict with one another; it is *not* intended to be a review by the Reliability Coordinator of the technical aspects of the GMD Operating Procedures or Operating Processes. The Transmission Operator is responsible for the technical aspects of its Operating Procedures or Operating

Processes pursuant to Requirement R3. For example, if Company A submitted an Operating Procedure proposing to take Line X out of service at specified GMD conditions and Company B submitted an Operating Procedure that relies on Line X remaining in service in the event of a GMD -- it is the responsibility of the Reliability Coordinator to *identify* this conflict. The Reliability Coordinator would then require Company A and Company B to resolve this conflict and resubmit their Operating Procedures. The drafting team believes that the coordination and resolution of identified operating conflicts can be resolved using existing agreements and processes.

- **Applicability to all networks greater than 200 kV with grounded-wye transformers. Some commenters indicated that 300 kV threshold is the appropriate voltage threshold based on the Oak Ridge National Labs report or other unspecified utility research. Another commenter stated that the 200 kV minimum voltage threshold was imprudent because a large population of transformers would not be covered or protected by the operating procedures, and that an unacceptable opportunity for GIC to enter the transmission network was permitted. One commenter recommended alternate wording in the applicability section. One commenter reiterated earlier comments that the applicability should be limited to single-phase transformers.** The drafting team believes the applicability section is worded clearly and would not be improved with the suggested wording. The drafting team agrees that single-phase transformers are more susceptible to half-cycle saturation due to GIC than three-phase three-limb core units, but does not agree that core construction is appropriate for use in determining applicability. Reactive power absorption in three-phase three-limb core units could have system impacts in some networks.

  The effect of GIC in networks less than 200 kV has negligible impact on the reliability of the interconnected transmission system. Using a voltage threshold higher than 200 kV could potentially create a reliability gap in many systems by excluding from the reliability standard a portion of the network that can be affected by GMD. Establishing 200 kV as the lower-bound threshold is consistent with operating experience and modeling guidance provided in the peer-reviewed technical literature. The drafting team's technical justification for establishing a 200 kV threshold in the applicability of EOP-010-1 is posted to the project page. (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx).
- **Applicable functional entities.**
  - **Balancing Authority. A commenter stated that Balancing Authorities needed to be included as an applicable functional entity in order for the RC to effectively coordinate Operating Procedures.** The SDT agrees that Balancing Authorities have a role in GMD response, as with many other reliability risks. This role is adequately covered by the real-time responsibilities described in the NERC Functional Model and as required by other Reliability Standards.
  - **Generator Operator. Some commenters stated that Generator Operators should be included in the standard.** The SDT agrees that Generator Operators have a role in GMD response as with many other reliability risks. This role is adequately covered by the real-time responsibilities described in the NERC Functional Model and as required by other Reliability Standards. Generator Operators may be included in stage 2 standards.

- **Transmission Operator. One commenter indicated that the standard should apply to the RC only.** The functional model states that the Transmission Operator has responsibility and authority for the reliable operation of the transmission system within the Transmission Operator Area. Applicability of EOP-010-1 to the Transmission Operator is consistent with this responsibility and authority.
- **Time horizons. Some commenters recommended changes to time horizons, or additions to the rationale box to clarify the drafting team's intent.** When requirements include performance elements that take place over different time horizons, it is acceptable to include more than one time horizon. The drafting team clarifies that development of the GMD Operating Plans, Processes, or Procedures occurs in the Long-Term Planning Time Horizon, which is defined as a planning horizon of one year or longer. Maintenance of the GMD Operating Plans, Processes, or Procedures occurs in the Operations Planning Time Horizon. Implementation of GMD Operating Plans, Processes, or Procedures occurs in the Operations Planning, Same-Day and Real-Time Time Horizons depending on the activity. The drafting team did not agree with a comment that suggested removal of the Long-term Planning Time Horizon from Requirements R1 and R3. The drafting team agrees that this type of planning could occur in the Operations Planning time horizon, but because space weather follows an 11-year solar cycle it could also be viewed by an entity from a long-term planning perspective.
- **Alternate approaches using existing standards. Some commenters stated that existing standards already manage GMD impacts.** Order No. 779 directs NERC to develop new reliability standards or modify existing requirements to mitigate the risk of GMD. The SDT chose to develop new reliability standards as the most efficient means of providing improved reliability during GMD events, although the team has recognized that existing standards are related to EOP-010-1, as noted herein.
- **Additions to Requirements or new Requirements. A small number of commenters suggested substantive changes and the drafting team does not believe there is consensus support for substantive changes. For example, one commenter suggested that EOP-010-1 should be developed regionally, rather than as a continent-wide standard.** The drafting team believes that the approach in the standard is appropriate to ensure a common level of preparedness for GMD events continent-wide, while at the same time allowing flexibility for each entity to tailor its procedures and plans to account for regional and local considerations.

Organization	Yes or No	Question 1 Comment
CPS Energy	No	I beleive this standard should be developed regionally, not at a national level.
Flathead Electric Cooperative, Inc.	No	I believe that either this standard should only apply to the RC or the stage 1 directives should be addressed outside the standards process. Recent GDM events have shown little to no impact on the Bulk Electric System and creating a GDM Operating Plan

Organization	Yes or No	Question 1 Comment
		requirement and auditing process is likely to have little reliability impact other than blindly following the letter of these directives.
Foundation for Resilient Societies	No	Question 1:Our Foundation's Case Study on Maine and ISO New England's capacity to mitigate a severe solar geomagnetic storm (March 2013 - found on website www.resilientsocieties.org) reaffirmed our prior understanding that the Regional Coordinators (in this case ISO-New England) cannot adequately coordinate "operating procedures" to mitigate a severe GMD event without concurrent jurisdiction over Balancing Authorities (BAs) and Generator Operators (GOs). In a severe solar storm, the combination of generation reserves together with demand response reserves may not enable Regional Coordinators (RCs) to balance loads without active preparation and support of balancing authorities. For ISO-New England that would include Canadian resources and balancing operators beyond the authority and scope of FERC Order No. 779. In effect, the various balancing (BAL) standards do not include standards for emergency hydroelectric generation or protection of equipment, such as series capacitors and static VAR compensators (SVC), necessary to maintain voltage stability for power imported from Canada. Without power imported from Balancing Authorities outside of ISO-New England, which also may be at risk of concurrent Geomagnetically-Induced Current (GIC), reactive power consumption, and adverse harmonics, the New England region is more likely to be at risk of prolonged electric grid blackout. The rationale of NERC's drafting team for excluding Balancing Authorities from participation as responsible entities to fulfill "operating procedures" is stated in NERC's "Functional Entity Applicability" document, which states:"... Balancing Authorities (BA) should not be among the applicable functional elements because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events."To the contrary, as GIC equipment monitors are already deployed within some Balancing Authorities, BA's need to assess the performance and GMD-related deterioration of networks during the moderate solar geomagnetic storms in coming years. Balancing Authorities may benefit from modeling balancing options under degraded conditions, such as the loss of a key Static VAR Compensator. There are interplays between selection of equipment options, and selection of balancing

Organization	Yes or No	Question 1 Comment
		strategies to “operate through” moderate level solar storms. Further, commercially available GIC monitors now provide “operating procedure” choices for their programming. At what level should different alarms be set, and to which entity should these alarms be reported? BAs have a “need to know” and critical roles to play, in both advising about equipment upgrades and in making best use of, or de-energizing as needed equipment that impacts the ability to balance loads before, during and after a GMD event. For further information on GIC monitors that are now available, see the Foundation Comments of October 15, 2013 in Maine PUC Docket 2013-00415.Moreover, if the Balancing Authorities are full-time partners in "operating procedures" to be coordinated by the RCs, it is more likely that additional GIC monitors will be installed at key locations, and critical equipment such as SVCs, Extra High Voltage (EHV) transformers, and generators will be protected from tripping or permanent damage. Also, power transmission over High Voltage Direct Current (HVDC) ties that are vulnerable to tripping from GIC will be better planned and protected. Already in New England, the Phase II HVDC tie from Canada has tripped off during a solar storm.A second concern of our Foundation relates to the arbitrary limitation of equipment to be subject to "operating procedures" to those portions of utility networks with high-side voltage of 200 kV or higher. We understand that the lower voltage transformers have higher resistance; hence they are generally less susceptible to GIC entering the bulk power system. But there are so many more transformers under 200 kV--roughly double the total transmission mileage in the U.S. transmission infrastructure--and so many more opportunities for "GIC leakage" into the EHV transmission networks. It appears imprudent to exclude transformers in the 100 kV to 200 kV range from "operating procedures."PowerWorld has estimated that less than 60% of total MVAR enters the bulk power system through transformers at 230 kV or higher, in both New England and in Michigan. Other regions that have not been adequately modeled to date may also incur high "GIC leakage" from transformers with high-end voltage under 200 kV. Transformers supplying these additional MVARs may experience transmission congestion, adverse effects of harmonics through overheating and equipment vibration, and risks of equipment damage or total loss. The economics of "operating procedures" may well demonstrate benefits of some combination of

Organization	Yes or No	Question 1 Comment
		equipment installation and operating procedures to reduce the rate of "GIC leakage" into the bulk power system via transmission sub-systems operating below 200 kV. NERC has not done the financial analysis mandated by FERC Order No. 779, so NERC should not prematurely exclude these grid pathways subject to GMD-induced instability, unreliability, and reduced capacity utilization. It is also notable that much of the specialized equipment designed to provide reactive power or to stabilize voltages within design tolerances operate below 200 kV. Is this equipment to be excluded from protective "operating procedures" under Proposed NERC Standard EOP-010-1? Siemens, for example, identifies many Static VAR Compensators operating at less than 200 kV. CenterPoint's Crosby SVC (IOC 2008) operates at 138 kV. Brushy Hill (1986, Canada) operates at 138 kV. Entergy's Porter SVC in Texas (IOC 2005) operates at 138 kV. CenterPoint Energy's Bellaire (IOC 2008) operates at 138 kV; Exelon's 2 SVCs at Elmhurst operate at 138 kV. Entergy's Prospects Heights SVC near Chicago has 2 SVCs at 138 kV. Northeast's Glenbrook, CT STATCOM operates at 115 kV.In “Appendix 2, Detailed Summary of Power System Impacts from March 13-14, 1989 Geomagnetic Superstorm” of “Meta-R-319, Geomagnetic Storms and Their Impacts on the U.S. Power Grid” by John Kappenman (January 2010, Oak Ridge National Laboratory), a table of system impacts on Page A2-2 shows no less than 10 GIC impacts on equipment operating at a base voltage of less than 200 kV. This is real -world data during a moderate solar storm. In contrast, NERC offers only theorizing in its document, “Network Applicability, Project 2013-03 (Geomagnetic Disturbance Mitigation), EOP-010-1 (Geomagnetic Disturbance Operations), Summary Determination” that networks operating at less than 200 kV would not be affected by GIC. Real world data should trump the technical speculation of NERC. Networks operating at less 200 kV (and over 100 kV) are part of the Bulk Power System and should be included in standards for GMD mitigation.Increasingly, the Bulk Power System is connected to wind power generation, with many wind power systems at ocean boundaries that may import above-average GIC. Wind power systems are generally stepped up to less than 200 kV. Wind power transmission systems are increasingly outfitted with GIC monitors. So, if these facilities are excluded from "operating procedures," will that mean that the near-real-time GIC data now available to wind power operators will not be shared with the RCs? It is

Organization	Yes or No	Question 1 Comment
		notable that in the Maine PUC Docket 2013-00415, with documents retrievable via the Internet, John Kappenman of Storm Analysis Consultants reported in October 2013 that, depending upon the orientation of a solar storm, the single GIC monitor at Chester Maine might report little or no GIC, even in a large solar storm. This is the only near-real-time GIC data received by ISO-New England, the relevant RC. Why would NERC seek to exclude GIC monitors at wind generation-transmission interconnections below 200 kV from "operating procedure" management by the Regional Coordinators? This would appear to be imprudent and is likely to result in needless risks to bulk power system reliability. In FERC Order No. 777, 142 FERC Para 61,208, issued on March 31, 2013, FERC provided a rationale for extending a reliability standard below 200 kV voltages under circumstances where the assets under consideration "are critical to reliability." See FERC Order No. 777 at p. 23, in Docket RM12-4-000. All of the SVCs, STATCOMs, series capacitors, and prospective dynamic VAR compensators with voltage under 200 kV should be considered as equipment "critical to reliability" for purposes of GMD operating procedures.Finally, our Foundation is alarmed that Generator Operators are now excluded from "operating procedure" jurisdiction in the proposed standard. Why?The NERC Drafting Team determined “that Generator Operators should not be among the applicable functional entities because any operating procedure to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment.”We find these rationales to be implausible. Generator Operators have, for more than a decade, utilized formulae provided (by ABB and other vendors) to down-power generation, hence loads on unprotected EHV transformers. There is operating experience with these “down-powering” practices that need to be shared as “best practices” or unacceptable practices. Those Generator Operators that already have installed GIC monitors, working with regional models, have already produced estimated of field voltages that will or will not collapse regional transmission networks. It would be imprudent to wait until every Generator Operators has GIC monitors at every GSU transformer to develop “operating procedures” that can protect critical equipment using cost-effective strategies. Another reason to bring Generator Operators into “operating procedure” practices as soon as possible is to help educate Generator Operators to understand the

Organization	Yes or No	Question 1 Comment
		practical limits of “operating procedures” for Generator Operators with equipment running at “GIC hotspots.” Neutral ground blocking devices not only eliminate virtually all GICs entering GSU transformer, but also reduce vulnerabilities of other GSU transformers that are unprotected within regional networks. The sooner executives of Generator Operators learn whether they will benefit from hardware protecting investments, the better. See the Foundation’s reproduction of a NOAA (Denver) initiative to display the frequency of half-cycle solar GMD events for the period 1958-2007 (Figure 20), indicating an above average risk in the years following solar maxima. The last solar maximum occurred in September 2013. See the Foundation Reply Comment of October 15, 2013 in Maine PUC Docket 2013-00415. FERC’s Order No. 779 seeks expedited protection of the bulk power system, not endless delays of needed protections. Many Generator Operators own and operate GSU transformers that at risk for damage due to GICs entering their GSU transformers and the bulk power system. Some Generator Operators, e.g. NextEra, have spun-off subsidiaries that can qualify their EHV transformers for OATTS cost-recovery by transferring ownership into a closely held transmission company. In either case, Generator Operators are key players in determining whether to downpower during a space weather-warning period. Many Generator Operators are also aware that the harmonics from GICs that enter their systems cause both overheating and vibrational effects on other equipment such as: generator stators, stator cooling pipes, and generator turbines. To exclude Generation Operators from "operating procedures" appears unfounded and a possible aggravating factor in a severe solar geomagnetic storm. Lastly, NERC needs to address what can be done to protect high-cost,long-replacement-time equipment during a severe solar storm, such as the New York Railroad storm of May 1921. Will the Nuclear Regulatory Commission preemptively order the de-energizing of all nuclear generating facilities and associated GSU transformers? Should the President order the de-energizing of all unprotected GSU transformers, including those without neutral ground blocking or designs projected to survive impending GMD events? If so, how will the Generator Operators protect their equipment, train personnel to validate and authenticate de-energization orders, and plan for optimal "black start" procedures? Excluding Generation Operators from the jurisdictional scope of "operating procedures" appears

Organization	Yes or No	Question 1 Comment
		to be based on the convenient but false assumption that the only solar geomagnetic storms for which electric utilities need prepare are those of moderate strength and short duration.We cannot in good conscience vote "yes" for a proposed standard for "operating procedures" that excludes Balancing Authorities, excludes Generator Operators, excludes critical equipment operating at under 200 kV, and excludes operators of GIC monitoring equipment from a mandate to share safety-related information in near-real time. NERC and the electric utility industry can achieve more effective standards. If this standard is approved by NERC as proposed, FERC should require key modifications in its review process.
Public Service Enterprise Group	No	R2 states “Each Reliability Coordinator shall disseminate forecasted and current space weather information as specified in the Reliability Coordinator's GMD Operating Plan.” We agree, but in R1 which requires such a plan, there is not requirement related to R2. We believe R1 should have subpart 1.1 rewritten as follows:1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area WHICH INCLUDE AN ACTIVITY TO DISSEMINATE FORECASTED AND CURRENT SPACE WEATHER INFORMATION.
SPP Standards Review Group	No	We propose changing the wording in Section 4.1.2 under Applicability to read:Transmission Operator with a Transmission Operator Area that includes a power transformer with a high-side, wye-grounded winding with a terminal voltage greater than 200 kV.This clarifies that the 200 kV winding is the high-side, wye-grounded winding.We suggest changing the ‘the Reliability Coordinator Area’ to ‘its Reliability Coordinator Area’ in R1.2.We suggest replacing ‘respective system’ with ‘Transmission Operator Area’ in R3. This language would then parallel that of R1.
American Electric Power	No	While AEP welcomes the removal of the word “coordinate” as an action performed by the RC, the word is now used as something that is done by the Operating Plan. Despite this change, and because the RC is required to implement the Operating Plan, there still appears to be an “implied” obligation where the RC must coordinate. This term remains

Organization	Yes or No	Question 1 Comment
		vague, and more specific text should be used in its place such as “affirm the compatibility of Operating Procedures and Operating Processes among the entities within the Reliability Coordinator Area.”Operating Plans developed by Reliability Coordinators may be quite different from area to area, which may be necessary in some circumstances. However, because AEP serves in multiple Operating Regions, we hope that the various Operating Plans, when feasible, are uniform for the most part. R1 states that the Operating Plan must coordinate GMD Operating Procedures, but makes no mention of the Operating Process as required in R3. Similarly, R1.2 requires a process to review GMD Operating Procedures but again makes no mention of reviewing Operating Processes. We recommend adding “Operating Processes” in R1 and R1.2, so that R1 reads “Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area.” and that R1.2 reads “A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators in the Reliability Coordinator Area.”
Independent Electricity System Operator	Yes	(1) We agree with all the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. However, we believe Part 1.2 should be expanded to convey the need for developing recourse. Part 1.2 stipulates that the RC’s GMD Operating Plan shall include:1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area.When a RC’s review of the TO’s operating procedures finds something lacking, then the recourse to make corrections should be made more clear. We suggest Part 1.2 be revised as follows:1.2. A process for the Reliability Coordinator to review the GMD Operating Procedures of Transmission Operators in the Reliability Coordinator Area, and direct the Transmission Operators to correct deficiencies, if any.If the SDT accepts this recommendation, please make a mirror change in R3 that will require the TOP to comply with the RC’s directive for correcting the deficiencies.(2) R2 as written is unclear on to whom the weather condition is to be provided. We suggest R2 to be clear that the RC is disseminating

Organization	Yes or No	Question 1 Comment
		space weather information to TOPs, as stated in the Background Information in the Comment Form "A new Requirement R2 has been added to the standard, which would require RCs to disseminate space weather forecast information to TOPs in the Reliability Coordinator Area (RCA).(3) R3 - The term 'Operating Process' is unnecessary and inconsistent with the wording in R1. We suggest to remove "or Operating Process" from R3 in the statement "Each Transmission Operator shall develop, maintain, and implement an Operating Procedure or Operating Process...".
ACES Standards Collaborators	Yes	1) The draft standard is much improved over the previous version. We thank the drafting team for removing the administrative requirements and removing BA applicability. We also agree that the standard does address the FERC directive. However, we believe there is another option that is as equally effective, is actually more efficient than writing a new standard and eliminates the redundancy that this proposed standard creates. The other option is to rely on existing standards. TOP-001-1a R2 and R8 already require the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. EOP-001-2 R2.2 requires the TOP to "develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system." IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an "all hazards" approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry's excellent response to large events such as hurricanes has proven the "all hazards" approach to planning is effective. Since these standards requirements are applicable at all times including during GMD events, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements.

Organization	Yes or No	Question 1 Comment
Hydro One	Yes	A process for the RC to review the GMD Operating Procedures of TOs in the RCA from the point of view of coordination is needed.
Colorado Springs Utilities	Yes	o Thank you for your efforts. The standard drafting team has not provided sufficient technical justification for the 200 kV threshold. Utility research indicates that the threshold should begin more around the 300kV threshold.
Electric Reliability of Texas, Inc.	Yes	ERCOT generally supports the SDT's efforts in developing the draft GMD standard and believes it is on the right track. However, the SDT should consider the following comments in the development of future versions.Most of the requirements seem to be concentrating upon the administration of “having procedures”. The standard should say “what” is required, while minimizing the required administration activities.1) Applicability Section The SDT should consider the role of GOPs in the standard. The standard in both its initial and revised form does not address the GOP function. GOPs may have GMD operating plans in place. As the whitepaper on applicable functions noted - “Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure.” Given that generators may have GMD procedures in place, the standard should reflect those procedures on a stand alone basis and as inputs into the larger operational GMD procedures. The failure to consider those plans in developing and coordinating the broader scope operational plans would create a disconnect between core operational roles. Such disconnects could undermine the effective and efficient management of GMD events potentially creating an undesirable reliability impact on the interconnection. Accordingly, the SDT should consider revisions to include the GOP function to ensure generator GMD procedures are considered and reflected in the larger scope GMD operational procedures. These plans should be coordinated with the relevant TOP and RC plans in a coordinated manner that is ultimately overseen by the RC, as proposed in the standard. 2) Requirement 1.2 The revised standard removes the coordination/compatibility determination role of the RC. It seems the RC should be performing these roles to

Organization	Yes or No	Question 1 Comment
		ensure effective and efficient operations in the context of a GMD event. It is not clear that a simple “review” role is adequate to achieve that outcome. The SDT should reconsider whether the RC should have the ability/authority to address any potential conflicts in plans pursuant to a coordination/compatibility determination role. If the revision was intended to simply be a “clean-up” edit, and that the coordination role is adequately covered in the R1 coordination role, R1 should reference R 1.2, so it is clear that the plans referenced in R1 are defined in terms of the specific functional entity referenced in R1.2.3) Measure 1 The revisions to M1 includes language that calls for evidence related to implementation to be that which demonstrates the entity performed the action "as called for in the GMD Plan...".While ERCOT understands the value of linking implementation evidence to the plan, the way it is drafted it could be interpreted very rigidly such that any operational deviation from the plan would be a violation. Obviously if you have a plan it should be used, but neither the standard nor the measure should be so rigid that if the operators cannot deviate from the plan if necessary based upon unintended circumstances without the risk of noncompliance with this requirement - entities should be able to take actions outside the four corners of the plan if necessary, and the standard and compliance measures should clearly accommodate such actions to avoid unintended consequences where the best operational actions are not taken because entities do not want to risk noncompliance.4) Requirement 2 Requirement 2 mandates that the RC share forecasted and current space weather information in accordance with its plan. As an initial matter, this implicitly requires RCs to have forecasted and current space weather information in our plans even though the substantive requirements related to the plan in R1 don't require that. This creates ambiguity in terms of whether that is a substantive obligation for the plan. For example, can an RC not have this in their plan, and, if so, does that make that requirement inapplicable in an audit? Another potential ambiguity related to this requirement is that there is no direction in terms of the entities the RC is required to disseminate this information to under the requirement. ERCOT understands the standard leaves this to the RC plan, but again, does that mean the RC does not have to have this in its plan? If this obligation is retained, the scope should be aligned with the functional entities in the standard that have GMD procedural roles (currently just TOPs

Organization	Yes or No	Question 1 Comment
		- although as noted ERCOT questions whether GOPs need to be included in the standard). Also, if this is going to be a plan requirement that should be explicit. To make it clear, it should be established as a substantive component of the plan as part of R1. However, ERCOT does not support this as a substantive requirement. The standard should dictate the substance of functional entity plans.ERCOT also questions the need for the RC to disseminate that information. The information can be obtained by other functional entities independent of RC dissemination, and that obligation, if the SDT elects to require entities to obtain this information, should be assigned to those entities. As drafted, this unnecessarily creates an opportunity for RC non-compliance with what is really administrative obligation i.e. distributing information that can be obtained independent of the RC. To the extent there is an inconsistency risk in terms of the sources/substance of this information, that risk could be managed by the RC coordination role.In addition to the above issues, the requirement is otherwise vague and ambiguous in terms of the scope of the information disseminated. For example, what is the timing for the dissemination? Again, the draft language leaves this to the RC plan, but as discussed, it is not clear if the RC has to have anything related to this, and if it does not, what the impact of that would be in an audit. If this implicitly requires the RC to have this process in its plan, the issue is what is the scope for all aspects - e.g. audience, timing, etc.? Granted the way it is drafted the RC has complete discretion, but there is a concern whether that discretion will be respected by the ERO in the exercise of its CMEP function.To mitigate the potential issues with this requirement, ERCOT believes it should be removed because the standard should require a plan, but should not dictate the substantive components of the plan. Alternatively the standard should be revised to make the obligations explicit and clear with respect to what is required - e.g. R 3.1 makes it clear that TOPs are required to have a process to obtain space weather information.5) Requirement 3 Related to the above comments on R2, R3 requires TOPs to get space weather info. Given this independent obligation, why does the RC have an obligation to disseminate that info? As discussed, it is unnecessary and creates unnecessary compliance risk.6) Requirements 3.2 and 3.3 As drafted, these requirements seem too prescriptive. While it is reasonable that a plan establishes actions relative to specific conditions. However,

Organization	Yes or No	Question 1 Comment
		the language should be clear that these are recommended actions, but are illustrative and non-exclusive. Functional entities should have the flexibility necessary to take actions outside of the plan if operating conditions change and counsel for operating actions outside of the four corners of the plan.7) Measure 3 Similar to the above comment on Measure 1, as drafted, Measure 3 could be interpreted in a manner that is too prescriptive and limiting, which could create the risk of undermining effective operations by limiting operator actions to the four corners of the plan or risk noncompliance risk. This would undermine the operational flexibility necessary to act outside of the plan if system conditions warranted such actions without risking violation of the requirement.
SERC OC Review Group	Yes	In R1 the requirement calls for the RC to review an “Operating Procedure”. We request the SDT to consider adding “Operating Process” so it is consistent with R3.
Duke Energy	Yes	In R1.2, the requirement calls for the RC to review an “Operating Procedure”. Duke Energy recommends adding “Operating Procedure or Operating Process”for consistency with R3.
US Bureau of Reclamation	Yes	The Bureau of Reclamation (Reclamation) appreciates the drafting team’s decision to require Reliability Coordinators (RCs) to disseminate space weather information rather than requiring each TOP to acquire and disseminate space information.
Northeast Power Coordinating Council	Yes	The Time Horizon brackets for Requirement R1 incorporate four (4) Time Horizons shown as: [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]It is not clear which Time Horizon goes with what part of Requirement R1. Suggest adding the clarification in a Rationale Box as follows:Development of the GMD Operating Plan is in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan is in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan is in the Same-Day and Real-Time Time Horizons.

Organization	Yes or No	Question 1 Comment
ISO/RTO Council Standards Review Committee	Yes	We agree with most of the proposed changes, and commend the SDT for responding positively to industry comments especially those that propose removal of the P.81 type of requirements, and the apparent redundancy/overlap with IRO-005-3.1a, R3. Nevertheless, we offer the following comments intended to further improve the standard.1. Certain wording in the proposed R2 introduces an unclear requirement in R2 and implied requirements in R1. R2 stipulates that the RC shall dissemintate forecasted and current space weather information “as specified in the Reliability Coordinator's GMD Operating Plan”. It is not clear what is it in the GMD Operating Plan that the RC must follow: is it the entities to whom the RC need to disseminate the information, or is it the forecast and current space weather information, or is it the timing for the dissemination, or a combination or all of the above? R1 does not provide this detail.We suggest the SDT to either add the detail in R1, or to remove or reword the phrase “as specified in the Reliability Coordinator’s GMD Operating Plan” to remove the uncertainty and implied requirement.2. We would also suggest some wording change to R1, which currently stipulates that:R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures within its Reliability Coordinator Area.A plan does not “coordinate”. Depending on the intent of the requirement - whether it mandates the RC to coordinate the GMD operating procedure or the RC to have a GMD operating plan that contains the coordinated operating procedures, and to more specifically indicate who to coordinate with, a more appropriate wording could be:”Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan to coordinate GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.”Or, the wording could be:”Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that reflects (or covers or stipulates) the coordinated GMD Operating Procedures of the Transmission Operators within its Reliability Coordinator Area.”
Xcel Energy	Yes	We have the following additional comments, but don’t view them as show stoppers.Because R2 specifies that the RC must disseminate space weather information

Organization	Yes or No	Question 1 Comment
		as specified it he RC GMD Op Plan, it would seem logical that there be a sub requirement in R1 that requires the RC has a process to distribute the space weather and list the entities and/or functions for distribution.R3.1 seems unnecessary since R2 requires the RC to disseminate space weather info, presumably the TOPs are included. It isn't clear what steps or tasks an entity would have to 'receive' space weather information.
NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Co.	Yes	
PacifiCorp	Yes	
Manitoba Hydro	Yes	
Public Utility District No.1 of Snohomish County	Yes	
Idaho Power	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Oncor Electric	Yes	

Organization	Yes or No	Question 1 Comment
Delivery Company LLC		
NV Energy	Yes	
Seminole Electric Cooperative, Inc.		Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of system topology, including geographical orientation, in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures:"An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures."Seminole acknowledges that the SDT did not adopt this suggestion during the last comment period for the reason that the SDT did not wish to begin naming criteria that could be utilized in documenting an Operating Plan, i.e., an exhaustive list. However, while reviewing the SDT's Network Applicability document posted with this Standard, NERC incorporated two out of the three Network Definition Considerations into the Proposed Standard, those two being the wye-grounded power transformer requirement and the lower limit voltage of 200 kV, while not adopting the system topology consideration. Seminole agrees with NERC that this is an important consideration in assessing GMD impacts and believes that this should be incorporated into the Standard in a manner that does not restrict additional considerations. As previously noted, the above suggested language comes directly from the SAR for this project.

2. **Do you agree that the VRFs and VSLs support the reliability objectives of the standard and meet FERC and NERC guidelines? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The drafting team thanks all who commented on the VRFs and VSLs. The Standard Drafting Team applied the NERC criteria and FERC Guidelines when proposing VRFs and VSLs for EOP-010-1. A justification has been posted to the project page (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx).

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	Because we question the need for the standard at this juncture, we cannot support the VSLs or VRFs. At best, the VRFs should all be low. For a requirement to be assigned a Medium VRF, a single violation of the requirement would have to “directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system” as defined in the Medium VRF definition. A single violation of any of these requirements will not “directly affect the electrical state or the capability of the bulk electric systems, or the ability to effectively monitor and control the bulk electric system.” Other standards would have to be violated first. For example, both TOP-002-2.1b R8 and TOP-004-2 R6.1 would have to be violated as well to effect the electrical state, monitoring and control of the bulk electric system. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Other requirements that would have to be violated include EOP-001-2 R2.2 and IRO-014-1 R1.
American Electric Power	No	We do not believe failure to meet R3.3, i.e. failure to terminate the Operating Procedure or Process after a GMD event, justifies a Medium VRF. Instead, a “Low” VRF is

Organization	Yes or No	Question 2 Comment
		recommended.
Flathead Electric Cooperative, Inc.	No	
CPS Energy	No	
Centerpoint Energy	No	CenterPoint Energy does not believe the lack of a documented procedure should produce a High VRF or Severe VSL.
Public Utility District No.1 of Snohomish County	Yes	Because GMD can be a wide area event the TOP efforts should focus on coordinating operations and procedures with the RC. Also, GMD is a high-impact, low-frequency event so overall risk to the TOP should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
SPP Standards Review Group	Yes	We would prefer to see the VRFs at Low rather than the assigned Medium, but can live with them as proposed.
Northeast Power Coordinating Council	Yes	
SERC OC Review Group	Yes	
Duke Energy	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Co.	Yes	
PacifiCorp	Yes	
Colorado Springs Utilities	Yes	
US Bureau of Reclamation	Yes	
Foundation for Resilient Societies	Yes	
Manitoba Hydro	Yes	
Hydro One	Yes	
Idaho Power	Yes	
Independent Electricity System Operator	Yes	
Electric Reliability of Texas, Inc.	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Question 2 Comment
Company LLC		

3. The Implementation Plan provides conditions for determining when the Requirements in EOP-010-1 become effective in each jurisdiction. Do you agree with the Implementation Plan as written? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The drafting team thanks all who commented on the Implementation Plan. Some stakeholders also commented that the six-month implementation period was too short. The drafting team believes that the requirements of the proposed standard can be met within that period. One commenter expressed concern that the stage 2 standards could affect the implementation or applicable entities of EOP-010-1. The drafting team believes the scope and purpose of the two stages in Project 2013-03 are properly established and separate as described in the Standard Authorization Request.

Organization	Yes or No	Question 3 Comment
CPS Energy	No	Implementation should be at the regional level
Arizona Public Service Co.	No	The implementation period should be no less than 1 year, 6 months implementation time would cause significant strain and will not allow an effective procedure to be developed.
Oncor Electric Delivery Company LLC	No	The Implementation Plan timeline calls for implementation 6 months from the standard approval or on the first day following the retirement of IRO-005-3.1a. This timeline does not provide sufficient time to create the necessary procedures or processes and train necessary personnel to those processes and procedures. The preferable timeline would be for implementation 12 months from the standard approval or on the first day following the retirement of IRO-005-3.1a, whichever is later.
Flathead Electric Cooperative, Inc.	No	
Xcel Energy	Yes	none

Organization	Yes or No	Question 3 Comment
Public Utility District No.1 of Snohomish County	Yes	Public Utility District No.1 of Snohomish County agrees in general, however appropriate implementation time should be given so that the Reliability Coordinator ("RC") has the time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions.
US Bureau of Reclamation	Yes	Reclamation appreciates the drafting team's efforts to avoid a situation where both IRO-005-3.1a Requirement R3 and EOP-010 Requirement R2 are effective at the same time.
SPP Standards Review Group	Yes	The treatment of the Effective Date in the standard appears to address the issue of implementation in the Canadian provinces. Hopefully this will resolve the issue.
ACES Standards Collaborators	Yes	While we continue to believe there is another equally efficient and more efficient alternative to development of this standard, the implementation plan is reasonable within the constraints of this standard. However, we have concerns that the second phase of this project may alter the work done in phase one, including modifications to the implementation plan and the entities that could be subject to compliance with this standard.
Northeast Power Coordinating Council	Yes	
NERC Compliance Policy	Yes	
SERC OC Review Group	Yes	
Duke Energy	Yes	
ISO/RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Colorado Springs Utilities	Yes	
Foundation for Resilient Societies	Yes	
Manitoba Hydro	Yes	
Hydro One	Yes	
Idaho Power	Yes	
Independent Electricity System Operator	Yes	
Electric Reliability of Texas, Inc.	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
NV Energy	Yes	

4. If you have any other comments for the drafting team to consider that you haven't already mentioned, please provide them here:

Summary Consideration: The drafting team thanks all who responded. The drafting team adopted a number of suggestions for clarifying the standard. A small number of commenters suggested substantive changes such as adding Requirements or language, but the drafting team does not believe there is a consensus to make substantive changes to the standard at this time. A summary of comments and the drafting team's response is provided below:

- **Predetermined conditions required for GMD Operating Procedures or Operating Processes. A commenter suggested the qualifier "if known" be added to Requirement R3 part 3.2 so entities without a study or GIC measuring equipment would not be required to include predetermine conditions for operator actions in the GMD Operating Procedure or Operating Process.** The drafting team believes that the requirement as written provides the flexibility to use good professional judgment to develop effective GMD Operating Procedures and Operating Processes.
- **Tailoring of operating procedures. A commenter requested that language be included in Requirement R3 to reflect that entities are allowed to consider various entity-specific factors in developing GMD Operating Processes or Operating Procedures.** The drafting team agrees with the principle that an entity can consider entity-specific factors in developing its process and procedure and has provided for this in the standard. The following has been added to the rationale box to describe the drafting team's intent: "In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology."
- **Transmission Operator responsibility to receive space weather information. A commenter stated that Requirement R3 part 3.1 should be removed since Requirement R2 placed responsibility for providing this information on the RC.** The drafting team believes that receiving space weather information is an essential component to GMD Operating Procedures or Operating Processes. EOP-010-1 recognizes that Transmission Operators may use several sources in addition to the Reliability Coordinator's disseminated forecast information to obtain more detailed local or system-specific information.
- **Requirement to ensure coordination between Reliability Coordinators. A commenter recommended a requirement be included added to require adjacent Reliability Coordinators to share their respected GMD Operating Plans.** The SDT believes coordination between and among Reliability Coordinators is adequately addressed in existing IRO standards. (Refer to IRO-014, Requirement R1).
- **A commenter recommended revising the SAR to include the term Operating Processes as currently used in the standard.** The SAR, as accepted by the Standards Committee, adequately defines the project scope without the recommended change.

- **A commenter suggested alternate wording for Requirement R3 part 3.3 (terminating the GMD Operating Procedure or Operating Process).** The drafting team considered the suggested alternate wording and determined that the suggested change did not provide additional clarity.
- **A commenter identified a correction needed in the Functional Entity Applicability whitepaper that the drafting team has incorporated.** The revised Functional Entity Applicability whitepaper (clean, and redline showing the changes made) has been posted on the project page (.http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx)
- **A commenter recommended a change to Requirement R3 to indicate that the GMD Operating Procedures or Operating Processes were intended to mitigate the effects of GMD events.** The drafting team considered the proposed language and determined that the suggested change did not provide additional clarity.
- **A commenter reiterated that system studies should be performed before operating procedures should be required.** The drafting team believes that the standard as written provides the flexibility to use good professional judgment to develop effective GMD Operating Procedures and Operating Processes.

Organization	Yes or No	Question 4 Comment
ISO/RTO Council Standards Review Committee	No	
Manitoba Hydro	No	
Hydro One	No	
Flathead Electric Cooperative, Inc.	No	
Idaho Power	No	
Oncor Electric Delivery Company LLC	No	
CPS Energy	No	

Organization	Yes or No	Question 4 Comment
Arizona Public Service Co.	Yes	Suggest changing R3.2 to as follows:System Operator actions to be initiated based on predetermined conditions, if known to be a susceptible to GMD. During the Webinar, it was pointed out that TOP is not required to have a study or measurement to find the predetermined conditions and most TOP would not know of such conditions existing in their system. The suggested language change would make it clear that they are not required to know the predetermined conditions.
ACES Standards Collaborators	Yes	(1) Requirement R2 should be made a sub-part of Requirement R1 to avoid double jeopardy and because it is essentially a constraint on the Operating Plan. If a registered entity fails to write an Operating Plan, it will also fail to include in its Operating Plan the method for disseminating space weather. Since violations are assessed per requirement, one compliance failure could result in two compliance violations of R2 and R3. Thus, if R2 is written as a sub-part of R1, failure develop an Operating Plan will be assessed as a single violation of the combined requirement. Furthermore, R2 essentially is a requirement for what should be contained in the Operating Plan and, therefore, more appropriately belongs as a sub-part of R1. (2) Part 3.1 in R3 is unnecessary and redundant with other requirements. R2 already compels the RC to disseminate space weather information. Because the RC is a higher authority than the TOP, the TOP is already required to receive the information as a result by implication. The RC's authority is documented in IRO-001-1a R3 and R8. The RC may issue directives to the TOP to follow its GMD Operating Procedure or Process while disseminating information about severe space weather. Furthermore, NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. Codifying a process that is already in place and works effectively only perpetuates the existing compliance model that places too much emphasis on documentation and not enough on reliability. (3) The SAR should be modified to indicate that Stage 1 will require registered entities to develop

Organization	Yes or No	Question 4 Comment
		and implement Operating Processes and Operating Plans in addition to Operating Procedures. The SAR only references the development and implementation of Operating Procedures which is not consistent with the standard that includes Operating Plans and Operating Processes. (4) We believe the literal meaning of the language in R3 Part 3.3 is not what is intended by the drafting team. As written, the language could be read to literally mean that the Operating Process or Operating Procedure must include language for retiring the Operating Process or Procedure. The problem is with the use of "terminate the Operating Procedure or Operating Process." Terminate means to come to an end. Thus, terminating the Operating Procedure or Operating Process which are documents means to end the document. Obviously, the purpose is to terminate the use of the Operating Procedure or Operating Process when the GMD event has ended. We suggest using the language from the SAR for R3 Part 3.3 as it is clearer and has a more exact meaning of what is intended. The language in the SAR is: "Criteria for discontinuing the use of Operating Procedures at the conclusion of a GMD event." (5) The Long-term Planning Time Horizon for R1 and R3 should be removed. The functional entities to which the standard applies are not planning entities per the functional model and have no long-term planning responsibilities. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on "Real-time conditions." An operating plan contains operating procedures and processes which are applied in real-time operations. (6) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify

Organization	Yes or No	Question 4 Comment
		their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will satisfy this required coordination. (7) The white paper supporting functional entity applicability should be modified. On page three, the last sentence just before the "Justification for Omitting Functional Entities" section is inconsistent with the standard. It states that "some procedures can be put in place by all TOPs." The standard limits the procedures to only TOPs with a transformer with a high-side wye-grounded winding greater than 200 kV. Please modify the sentence in the whitepaper for consistency with the standard. (8) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extreme GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southernmost entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies as documented in our responses to other questions.(9) Thank you for the opportunity to comment.
Colorado Springs Utilities	Yes	1. Thank you for all of your work SDT! 2. For the record. We have concern over the fact that action is being required prior to defining the risk? A blind shotgun approach consumes a lot of unnecessary resources, as it is anticipated that there are many entities that will not be at risk to GMDs. We understand that FERC is pushing for action, but think that their push should be founded on established risk.

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Agency	Yes	According to the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers connected in a grounded wye configuration. This is the primary reason for FMPA's negative vote.FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. The resistance of 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line. Although FMPA believes the threshold should be raised to 300 kV, we can "live" with a 200 kV threshold if the applicability to 200 kV is to TOPs that operate three single leg core design transformers connected in a grounded wye configuration.
Bonneville Power Administration	Yes	BPA recommends the drafting team change the language of the first sentence of R3, from “Each Transmission Operator shall...or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system.” To “Each Transmission Operator shall...or Operating Process intended to mitigate the effects of GMD events on the reliable operation of its respective system.”
Duke Energy	Yes	Duke Energy would like to thank the SDT for their response to stakeholder comments.
Foundation for Resilient Societies	Yes	For further background information on the Foundation's support of wider jurisdiction for coordinated "operating procedures" see our March 2013 case study of Maine and ISO-New England in a solar geomagnetic storm, found at www.resilientsocieties.org and the Foundation's comments responsive to queries by the Maine Public Utilities Commission, in MPUC Docket 2013-00415 (Oct 4, 2013), and our Supplemental and

Organization	Yes or No	Question 4 Comment
		Reply Comments in that same Docket (October 15, 2013).
Nebraska Public Power District	Yes	NPPD supports the comments submitted by the Southwest Power Pool. In addition we would like to add this comment:"The drafting team is requiring operating procedures to be in place prior to studying the GMD effects on the TOP system. To determine what effects the GMD will have on the TOP's system, the studies should be preform first and then the operating procedures developed. The drafting team is requiring generic operating procedures which may or may not address the GMD issues on the TOP's system. It makes more sense to delay the implementation of the operating procedures until the studies have been performed."
ReliabilityFirst	Yes	ReliabilityFirst votes in the affirmative because this standard will help to mitigate the effects of geomagnetic disturbance (GMD) events by requiring the Reliability Coordinator to implement Operating Procedures and the Balancing Authorities and Transmission Operators to implement Operating Plans. ReliabilityFirst offers the following comments for consideration:1. Requirement R1 - To be consistent with the language in Requirement R3, ReliabilityFirst believes the term "Operating Process" should be added to Requirement R1. Furthermore, Requirement R1 should include a statement tying it back to the Transmission Operator's Operating Procedure or Operating Process in Requirement R3. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures [and Operating Processes, as developed in Requirement R3,] within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:..."2. Consideration for new Requirement R4 - ReliabilityFirst submitted this comment during the last comment period but believes it may have been overlooked (i.e., we believe it was not addressed in the consideration of comments report). ReliabilityFirst recommends including a new Requirement R4 which would require adjacent Reliability Coordinators to share their respected GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators

Organization	Yes or No	Question 4 Comment
		should be aware of each other's GMD Operating Plans.
Oklahoma Gas & Electric	Yes	The Standard, as written, requires entities to have a plan, but it fails to identify a clear and measurable expected outcome, such as a stated level of reliability performance, a reduction in a specified reliability risk (prevention), or a necessary competency.
Northeast Power Coordinating Council	Yes	The text of the "Effective Dates" section should be consistent with the EOP family of standards to reduce the variance between EOP Standards.Regarding Requirement R1 and its Measure M1, times for completion need to be added. The Violation Severity Levels have to be revised accordingly.The contents of the Rationale Boxes for R1 and R3 as they shown are obvious, and can be removed. In the response to Question 1 above we suggested an addition to the Rationale Box for R1. The Rationale Box for R2 should not repeat wording from R2.
American Electric Power	Yes	The time horizon "Long-term Planning" seems more appropriate for the Stage 2 aspect of this GMD standard, and not for the Stage 1. Please provide carification for how Long-term Planning is to be applied for R1 and R3 as well as justification for doing so.Although this may be ouside the scope of this project team, we encourage NERC to resolve the discrepancies between the definition of Long-term Planning as provided in NERC's Time Horizon and the definition of "Long-Term Transmission Planning Horizon" in the NERC Glossary of Terms.AEP recognizes the perceived urgency of this project, supports the objective of the proposed standard, and appreciates the efforts of the drafting team. Our negative vote is driven solely by our desire for additional clarity as stated in our comments. AEP foresees voting in the affirmative once the issues and concerns expressed in this response are addressed in future versions of the draft.
Tri-State Generation and Transmission Association, Inc.	Yes	Tri-State is still concerned with the Standard Drafting Team's decision setting the limit of applicable transformers from >200kV versus >300kV. This critical decision will have significant cost and time ramifications on the industry. The workload for Tri-State will increase nearly five-fold based on the amount of transformers that fall into the 200-300kV range. We appreciate the work that the volunteer task force has accomplished in

Organization	Yes or No	Question 4 Comment
		helping to prepare the NERC “Network Applicability” paper, but Tri-State believes such a critical decision in setting the limit should be based on more extensive knowledge. The “Network Applicability” justification for including 200kV circuits is only based on an analysis of a small simulated network consisting of two 500/230kV autotransformers with only a few lines running into and out of that station. That analysis, summarized in Table A1 (pg. 7), predicts a decrease of GIC from 5.5 to 2.8 Amps if the 230kV elements are included. The study also estimates an increase in var absorption from 12.5 to 14 Mvar if the 230kV elements are included. Tri-State suggests that these slight variances are well within the error range in the overall assumptions for the many parameters used to predict GIC itself. Parameters such as the line induced kV/km, the magnitude and duration of solar events, the deep earth soils geology, accuracy of the transformer models, ground grid resistance (which may vary season to season), etc. Our suggestion is to give the NERC task force increased time to do research and in the meantime adopt a criteria of detailed analysis of >300kV with a 10% safety factor added for the possible <300kV impact.
SPP Standards Review Group	Yes	We want to thank the drafting team for taking the time to provide summary responses to help the industry’s understanding of the changes even though they didn’t have to.
PacifiCorp	Yes	
Public Utility District No.1 of Snohomish County		Although GMD and Geomagnetically Induced Currents (“GIC”) have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufacturers. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on the level of impact a GMD can have on the BES and what level of risk a GMD poses compared to other adverse impact events.
SERC OC Review Group		We would like to thank the SDT for their responses to stakeholder comments.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the

Organization	Yes or No	Question 4 Comment
		position of the SERC Reliability Corporation, or its board or its officers.

END OF REPORT

Draft 3

Stage 1 Standard

Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The draft standard was posted for a 45-day formal comment period and initial ballot from June 26, 2013 through August 12, 2013. The SAR was posted for informal comment during the same period.
3. The second draft of the standard was posted for a 45-day formal comment period and additional ballot from September 4, 2013 through October 18, 2013.

Description of Current Draft

This is the third posting of the proposed standard. It is posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
Final ballot	October 2013
BOT adoption	November 2013

Effective Dates

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

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03	N/A

Definitions of Terms Used in Standard

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

None

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**
2. **Number:** EOP-010-1
3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator
   4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Protection System Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area.

Rationale and supporting information for Requirement R1: An Operating Plan is implemented by carrying out its stated actions.

Coordination is intended to ensure that Operating Procedures are not in conflict with one another.

An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

Rationale and supporting information for Requirement R2: Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

R3. Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. Steps or tasks to receive space weather information.

3.2. System Operator actions to be initiated based on predetermined conditions.

3.3. The conditions for terminating the Operating Procedure or Operating Process.

Rationale and supporting information for Requirement R3: In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator and Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations Planning,	Medium	The Transmission Operator had a GMD Operating Procedure or Operating Process,	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator did not have a GMD Operating Procedure or Operating

	Same-day Operations, Real-time Operations		but failed to maintain it.	failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

D. Regional Variances

None.

E. Interpretations

None.

Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The draft standard was posted for a 45-day formal comment period and initial ballot from June 26, 2013 through August 12, 2013. The SAR was posted for informal comment during the same period.
3. The second draft of the standard was posted for a 45-day formal comment period and additional ballot from September 4, 2013 through October 18, 2013.

Description of Current Draft

This is the third posting of the proposed standard. It is posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Ballot~~	~~September 2013~~
Final ballot	October 2013
BOT adoption	November 2013

Effective Dates

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

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03	N/A

Definitions of Terms Used in Standard

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

None

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**

2. **Number:** EOP-010-1

3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and P~~p~~rotection S~~s~~ystem Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

> **Rationale and supporting information for Requirement R1:** An Operating Plan is implemented by carrying out its stated actions.
>
> Coordination is intended to ensure that Operating Procedures are not in conflict with one another.
>
> An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.
>
> Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within ~~the~~ its Reliability Coordinator Area.

M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information ~~as specified~~to functional entities identified as recipients in ~~in~~ the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

Rationale and supporting information for Requirement R2: Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

R3. Each Transmission Operator shall develop, maintain, and implement a GMD~~n~~ Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. Steps or tasks to receive space weather information.

3.2. System Operator actions to be initiated based on predetermined conditions.

3.3. The conditions for terminating the Operating Procedure or Operating Process.

Rationale and supporting information for Requirement R3:

In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

An Operating Procedure or Operating Process is implemented by carrying out its stated actions.

M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator and Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information ~~as specified~~to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations	Medium	The Transmission Operator had a GMD Operating Procedure	The Transmission Operator's GMD Operating Procedure	The Transmission Operator's GMD Operating Procedure or	The Transmission Operator did not have a GMD Operating

	Planning, Same-day Operations, Real-time Operations		or Operating Process, but failed to maintain it.	or Operating Process failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Operating Process failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Procedure or Operating Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

D. Regional Variances

None.

E. Interpretations

None.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator

Transmission Operator with a Transmission Operator Area that includes any transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

Requirement R2 of EOP-010-1 replaces Requirement R3 of IRO-005-3.1a. IRO-005-4 has been adopted by the NERC Board and filed with FERC in Docket Number RM13-15-000, and will retire Requirement R3 of IRO-005-3.1a:

IRO-005-3.1a, Requirement R3:

R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

EOP-010-1 replaces this requirement with the following:

EOP-010-1, Requirement R2:

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan**.**

Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, EOP-010-1 shall become effective as follows:

In jurisdictions where regulatory approval is required:

- The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in that jurisdiction.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

In jurisdictions where regulatory approval is not required:

- The first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation

Implementation Plan for EOP-010-1 – Geomagnetic Disturbance Operations

Approvals Required

EOP-010-1 – Geomagnetic Disturbance Operations

Prerequisite Approvals

None

Retirements

None

Revisions to Glossary Terms

None

Applicable Entities

Reliability Coordinator
Transmission Operator with a Transmission Operator Area that includes any transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Conforming Changes to Other Standards

None

Effective Dates

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IRO-005-3.1a, Requirement R3:

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EOP-010-1 replaces this requirement with the following:

EOP-010-1, Requirement R2:

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information ~~as specified~~to functional entities identified as recipients in ~~in~~ the Reliability Coordinator's GMD Operating Plan**.**

Therefore, to ensure responsibility for disseminating space weather information in the Reliability Coordinator Area is maintained while avoiding duplicative requirements being enforceable at the same time, EOP-010-1 shall become effective as follows:

In jurisdictions where regulatory approval is required:

- The first day of the first calendar quarter that is six months ~~beyond~~ after the date that this standard is approved by an applicable governmental authorit~~ies~~y or as otherwise provided for in that jurisdiction.~~made effective pursuant to the laws of applicable to these authorities.~~
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

In jurisdictions where regulatory approval is not required:

- The first day of the first calendar quarter that is six months ~~beyond~~ after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~made effective pursuant to the laws of applicable governmental authorities.~~ .
- If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Standards Authorization Request Form

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

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

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

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

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

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

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

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

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

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

Related SARs	
SAR ID	Explanation

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

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Network Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators and Transmission Operators with networks that contain power transformers with high side grounded wye windings above 200 kV. The drafting team concluded that this is the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. This lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature, as explained below.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779.

Justification

Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (115 kV lines are typically less than 15 miles in length), the resulting geomagnetically-induced current (GIC) generated by lines rated less than 200 kV are significantly less than those of higher voltages and are typically ignored in GIC analysis. Conversely, using a voltage threshold higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap by excluding a portion of the network that can be significantly affected by GMD. Results of sensitivity analysis conducted by the drafting team are presented in the appendix. It shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event.

Network Definition Considerations

Key parameters in the definition of a network for assessing GMD impacts are:

- Transformer grounding and core construction
  - Only wye-grounded power transformer windings provide a path for GIC
  - Transformer core construction (e.g., single-phase, three-phase, autotransformer) has an effect on the magnitude of var absorption and generated harmonics. Single-phase transformers are more susceptible to half-cycle saturation due to GIC relative to three-phase 3-leg units; however, the var absorption in 3-legged three-phase core units cannot be neglected.
  - Regardless of core construction, all grounded wye transformers have an effect in the distribution of GIC in the network
- System topology
- Geographical location
- Resistance values of the elements of the DC network used to evaluate GIC distribution within the network
  - Transmission line resistances per unit length increase as the voltage level decreases (see typical values in Table 1). (With the resistances shown in Table 1, the maximum neutral GIC contributed by a single 230 kV circuit is of the order of 30 A, as opposed to 75 A for a single 345 kV circuit.)

Selection of a network where the cut off is selected on the basis of wye-grounded power transformers with HV terminals > 200 kV

- Almost all peer-reviewed studies on the effects of GIC include networks > 200 kV [1-13].
- When lower voltage levels are included, the effects of including network elements < 200 kV are in most cases minimal [9]. (The Appendix shows an example of the effects of the inclusion/exclusion of the 115 kV network.)
- The absorption of reactive power in a saturated transformer depends on the system operating voltage and GIC. It does not depend on the nameplate rating of the transformer. In the case of single-phase power transformers, var absorption and harmonic generation are very insensitive to air-core reactance [11].

TABLE 1

TYPICAL NETWORK RESISTANCES FOR DIFFERENT VOLTAGE-LEVEL POWER GRIDS IN NORTH AMERICA

System Voltage Levels (kV)	DC Resistances of the Transformers (ohm)	Grounding Resistances of the Substations (ohm)	DC Resistances of the Transmission lines (ohm/km)
230	0.692	0.563	0.072
345	0.356	0.667	0.037
500	0.195	0.125	0.013
735	0.159	0.258	0.011

- Reactive power absorption of a saturated transformer is proportional to its HV voltage rating. Transformers < 200 kV have a relatively lower influence in the reactive power balance of the system (see Figure 1).

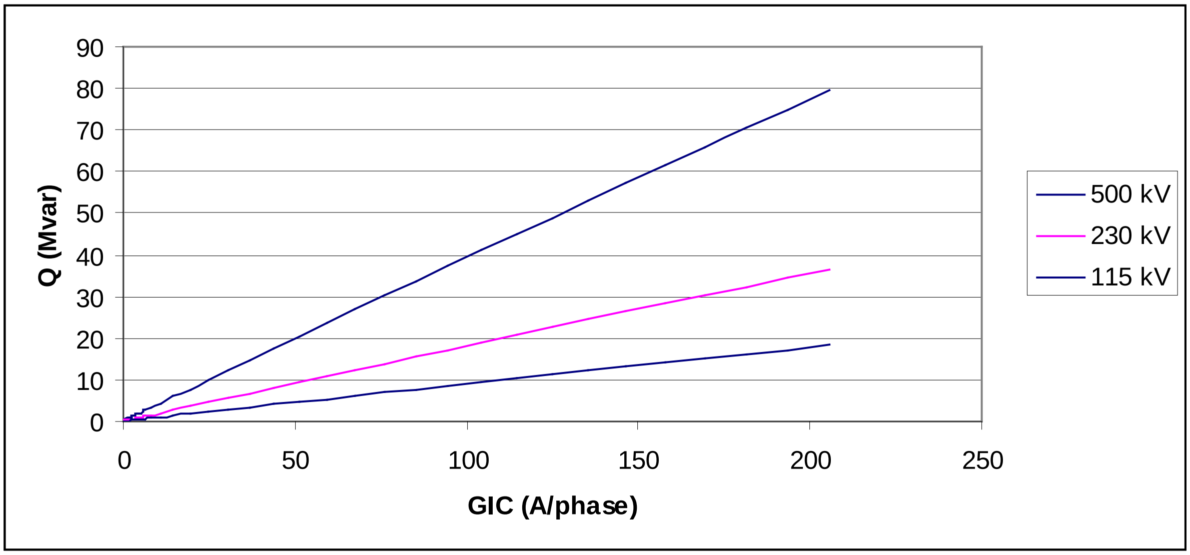

Figure 1: Reactive power absorption of a single-phase transformer vs. GIC

System Impact Considerations

A key element in a GMD event is the absorption of reactive power of high side wye-grounded transformers experiencing half-cycle saturation.

- In many jurisdictions bulk power transmission includes voltages > 200 kV. Tripping a transformer with high side voltage > 200 kV or reconfiguring > 200 kV circuits can impose serious constraints on operating limits; therefore, such operating scenarios must be considered in GMD impact studies.
- Generator step-up transformers are typically situated at electrical end points of the network where GIC tends to be highest. GSUs with high side voltages > 200 kV are not uncommon. On the other hand, GIC injected by circuits < 200 kV is limited because of the higher resistances of GSUs connected to < 200 kV networks
- Autotransformers are often used in networks above > 200 kV. The flow of GIC depends heavily on the relative resistances of various network elements and the geographical orientation of nearby transmission lines [14]. Considering a 500/230 kV autotransformer with one 500 kV and one 230 kV circuit, modelling GIC flow without taking into consideration the 230 kV circuit results in GIC overestimation between 20% and 30%. In a more complex configuration, the estimated GIC

ignoring the 230 kV circuits can over or underestimate GIC and the effects of GIC in transformers significantly. The appendix shows an example of this effect.

- From the point of view of GIC distribution in the network, transformer vulnerability is not a consideration. Including only transformers with high side windings > 300 kV would result in unrealistic GIC flow assessments (see Appendix)
- In systems where the bulk transmission voltages are 230 kV and 500 kV, neglecting circuits rated less than 300 kV would misrepresent GIC flows and var absorption, especially because GIC flow-through in 500 kV autotransformers would be neglected (see Appendix).

Appendix

This Appendix describes two examples where:

- The exclusion of 230 kV circuits at a station with 500/230 kV autotransformers cause significant errors in the estimation of GIC effects.
- The inclusion/exclusion of the 161 kV and 115 kV networks in a large utility within the Eastern Interconnect has minimal impact on the estimation of the effects of GIC in the system

Example 1: Exclusion of 230 kV circuits in a 500/230 kV transmission station

The distribution of GIC in a network, for a given geomagnetic latitude and earth structure, depends on a number of factors such as resistances of various circuit elements, induced voltages and network topology. There are times when a complex network topology can lead to non-intuitive results, such as the presence of a series capacitor causing an increase of GIC in a transformer.

To illustrate, consider the topology of the circuits connected to Transmission Station (TS) shown in Fig. A1. If a transmission circuit is sufficiently long it can be represented by a constant current source (since both induced voltage and line resistance are proportional to line length). In the case of a 500 kV circuit, GIC tends to be fairly constant for lengths > 150 km. A simplified representation is shown in Fig A2. The station has several autotransformers which have been lumped into a single equivalent autotransformer. The series capacitor bank is assumed to be out of service (bypassed).

Currents *I1* and *I2* represent the GIC contribution of the 500 kV circuits to the HV bus. Then,

$$I3 = I1 - I2 \tag{A.1}$$

where *I3* is the total contribution of the 500 kV circuits to the series winding. The total contribution to the common winding is given by

$$Ig = I3 + I4 + I5 + I6 - I7 \tag{A.2}$$

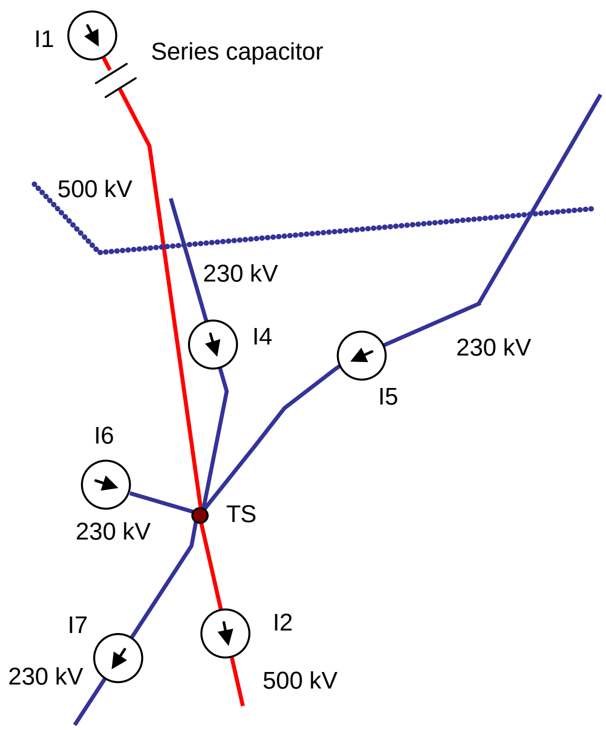

Fig. A1: HV transmission lines connecting to Essa TS.

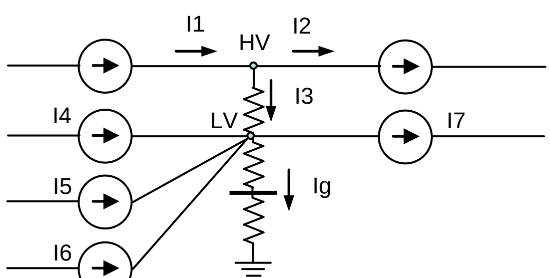

Fig. A2: Circuit representation of induced geoelectric fields and equivalent transformer representation.

Let us assume that the earth can be represented by a laterally-uniform earth model, and that the 500 kV circuits are in the same or similar orientation geographically with the same resistance per unit length, so that the injected GIC I1 and I2 are nearly identical (see Fig. A1). Then I3 will be small or zero and only the 230 kV circuits will contribute to the current in the transformer common winding Ig. If the 230 kV circuits were excluded, (i.e., I4 = I5 = I6 = I7 = 0) then I3 = Ig would be very small and the estimated effects of GIC on the autotransformer would be minimal.

If the 500 kV series capacitor bank in Fig. A1 is placed in service, then I1 = 0 and I2 = I3. The common-winding GIC is now equal to the sum of the GIC contributed by the 230 kV circuits and the remaining 500 kV circuit. Depending on the relative values of the contributions, the net GIC through the transformer may increase or decrease. Simulations show that in the network shown in Figure A1 when the series capacitors are in service, the effective GIC through the transformer increases by a factor of 30. This is not a general result, but rather a consequence of Kirchhoff's current law and a particular system topology.

If the series capacitor bank is in service and the 230 kV circuits are not taken into consideration all the GIC from the remaining 500 kV circuit would flow into the autotransformer and describe a completely different situation from in terms of the saturation of the autotransformer.

The cases described above were simulated with a GIC analysis tool and summarized in Table A1. Note that there are two 500/230 kV autotransformers in service in this simulation.

Table A1: Summary of the Effects of 230 kV Circuits in a Station with Two 500/230 kV Autotransformers

Geoelectric field 5 V/km	230 kV and 500 kV 500 kV Series caps in service	230 kV and 500 kV 500 kV Series caps bypassed	No 230 kV 500 kV Series caps in service	No 230 kV 500 kV Series caps bypassed
Transformer GIC/phase (A/phase)	99.9	2.8	127	5.5
I1 (A/phase)	0	365	0	338
I2 (A/phase)	146.8	334	254	349
Incremental metallic hot spot temperature (C°)	89	1.6	60	7.6
var absorption (Mvar)	128	14	151	12.5
THD (%)	17	2.5	18	2.2

The conclusion from this example is that it is not always possible to make generalizations in a network of relatively complex topology. While it is true that a series capacitor blocks GIC in the transmission line

where it is employed, it does not necessarily reduce GIC in system transformers. Furthermore, not taking into account the effects of the 230 kV circuits in this network would lead to inaccurate conclusions, such as a 33% underestimation of the hot spot temperature rise[1].

Example 2: Effects of the inclusion/exclusion of circuits below 200 kV

A portion of the Eastern Interconnect that contains 500 kV, 230 kV, 161 kV, and 115 kV facilities was modeled using PowerWorld software. When the GIC contribution of the 161 kV and 115 kV circuits was excluded, the effects on the network above 200 kV where found to be minimal. Table A2 summarizes the effects of including/excluding GIC contributions from the 161 kV and 115 kV network assuming a 5 V/km East-West geoelectric field. The differences in the results assuming a North-South geoelectric field are very similar, and are not reproduced in here.

Table A2: GIC Effects on the Network Above 200 kV Assuming an East-West 5 V/km Geoelectric Field

	Including 115 kV	Excluding 115 kV	Difference
Maximum transformer GIC (A/phase)	134.65	133.78	0.6 (%)
Average transformer GIC (A/phase)	13.79	13.46	2.4 (%)
Maximum transformer var absorption (Mvar)	150.3	149.5	0.7 (%)
Average transformer var absorption (Mvar)	7.16	7.08	1.1 (%)
Minimum bus voltage (pu)	0.98204	0.98548	0.4 (%)
Average bus voltage (pu)	1.01858	1.01897	0.04 (%)
Total system var loss due to GIC (Mvar)	3,935	3,801	3.4 (%)

These results are consistent with observations made in peer-reviewed technical publications such as [9].

[1] Hot spot heating was estimated using the methodology described in [15]

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Network Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators and Transmission Operators with networks that contain power transformers with high side grounded wye windings above 200 kV. The drafting team concluded that this is the minimum network voltage for which a reliability benefit can be expected from the application of GMD Operating Procedures. This lower-bound threshold is consistent with operating experience and modeling guidance provided in the literature, as explained below.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779.

Justification

Because transmission line resistance decreases by a factor of 10 from 69 kV to 765 kV and lower voltage lines tend to be shorter (115 kV lines are typically less than 15 miles in length), the resulting geomagnetically-induced current (GIC) generated by lines rated less than 200 kV are significantly less than those of higher voltages and are typically ignored in GIC analysis. Conversely, using a voltage threshold higher than 200 kV, such as 345 kV, for a lower-bound threshold could potentially create a reliability gap by excluding a portion of the network that can be significantly affected by GMD. Results of sensitivity analysis conducted by the drafting team are presented in the appendix. It shows that the GIC contribution from the 230 kV portion of the network can result in system impacts during a GMD event.

Network Definition Considerations

Key parameters in the definition of a network for assessing GMD impacts are:

- Transformer grounding and core construction
  - Only wye-grounded power transformer windings provide a path for GIC
  - Transformer core construction (~~e.g~~e.g., single-phase, three-phase, autotransformer) has an effect on the magnitude of var absorption and generated harmonics. Single-phase transformers are more susceptible to half-cycle saturation due to GIC relative to three-phase 3-leg units; however, the var absorption in 3-legged three-phase core units cannot be neglected.
  - Regardless of core construction, all grounded wye transformers have an effect in the distribution of GIC in the network
- System topology
- ~~, including g~~Geographical ~~orientation~~location
- Resistance values of the elements of the DC network used to evaluate GIC distribution within the network
  - Transmission line resistances per unit length increase as the voltage level decreases (see typical values in Table 1). (With the resistances shown in Table 1, the maximum neutral GIC contributed by a single 230 kV circuit is of the order of 30 A, as opposed to 75 A for a single 345 kV circuit.)

Selection of a network where the cut off is selected on the basis of wye-grounded power transformers with HV terminals > 200 kV

- Almost all peer-reviewed studies on the effects of GIC include networks > 200 kV [1-13].
- When lower voltage levels are included, the effects of including network elements < 200 kV are in most cases minimal [9]. (The Appendix shows an example of the effects of the inclusion/exclusion of the 115 kV network.)
- The absorption of reactive power in a saturated transformer depends on the system operating voltage and GIC. It does not depend on the nameplate rating of the transformer. In the case of single-phase power transformers, var absorption and harmonic generation are very insensitive to air-core reactance [11].

TABLE 1

TYPICAL NETWORK RESISTANCES FOR DIFFERENT VOLTAGE-LEVEL POWER GRIDS IN NORTH AMERICA

System Voltage Levels (kV)	DC Resistances of the Transformers (ohm)	Grounding Resistances of the Substations (ohm)	DC Resistances of the Transmission lines (ohm/km)
230	0.692	0.563	0.072
345	0.356	0.667	0.037
500	0.195	0.125	0.013
735	0.159	0.258	0.011

- Reactive power absorption of a saturated transformer is proportional to its HV voltage rating. Transformers < 200 kV have a relatively lower influence in the reactive power balance of the system (see Figure 1).

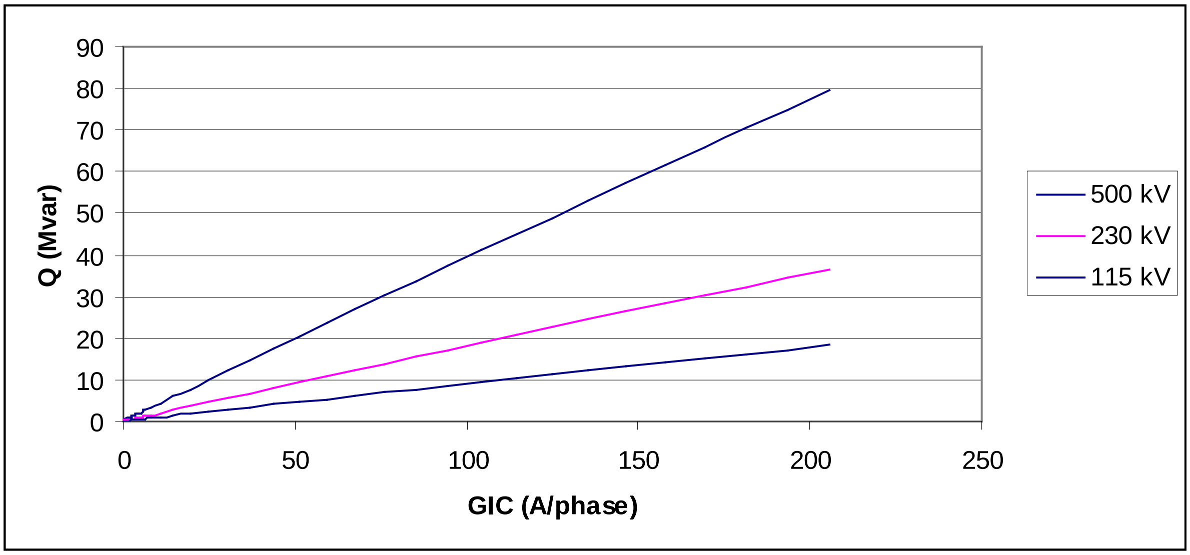

Figure 1: Reactive power absorption of a single-phase transformer vs. GIC

System Impact Considerations

A key element in a GMD event is the absorption of reactive power of high side wye-grounded transformers experiencing half-cycle saturation.

- In many jurisdictions bulk power transmission includes voltages > 200 kV. Tripping a transformer with high side voltage > 200 kV or reconfiguring > 200 kV circuits can impose serious constraints on operating limits; therefore, such operating scenarios must be considered in GMD impact studies.
- Generator step-up transformers are typically situated at electrical end points of the network where GIC tends to be highest. GSUs with high side voltages > 200 kV are not uncommon. On the other hand, GIC injected by circuits < 200 kV is limited because of the higher resistances of GSUs connected to < 200 kV networks
- Autotransformers are often used in networks above > 200 kV. The flow of GIC depends heavily on the relative resistances of various network elements and the geographical orientation of nearby transmission lines [14]. Considering a 500/230 kV autotransformer with one 500 kV and one 230 kV circuit, modelling GIC flow without taking into consideration the 230 kV circuit results in GIC overestimation between 20% and 30%. In a more complex configuration, the estimated GIC

ignoring the 230 kV circuits can over or underestimate GIC and the effects of GIC in transformers significantly. The appendix shows an example of this effect.

- From the point of view of GIC distribution in the network, transformer vulnerability is not a consideration. Including only transformers with high side windings > 300 kV would result in unrealistic GIC flow assessments (see Appendix)
- In systems where the bulk transmission voltages are 230 kV and 500 kV, neglecting circuits rated less than 300 kV would misrepresent GIC flows and var absorption, especially because GIC flow-through in 500 kV autotransformers would be neglected (see Appendix).

Appendix

This Appendix describes two examples where:

- The exclusion of 230 kV circuits at a station with 500/230 kV autotransformers cause significant errors in the estimation of GIC effects.
- The inclusion/exclusion of the 161 kV and 115 kV networks in a large utility within the Eastern Interconnect has minimal impact on the estimation of the effects of GIC in the system

Example 1: Exclusion of 230 kV circuits in a 500/230 kV transmission station

The distribution of GIC in a network, for a given geomagnetic latitude and earth structure, depends on a number of factors such as resistances of various circuit elements, induced voltages and network topology. There are times when a complex network topology can lead to non-intuitive results, such as the presence of a series capacitor causing an increase of GIC in a transformer.

To illustrate, consider the topology of the circuits connected to Transmission Station (TS) shown in Fig. A1. If a transmission circuit is sufficiently long it can be represented by a constant current source (since both induced voltage and line resistance are proportional to line length). In the case of a 500 kV circuit, GIC tends to be fairly constant for lengths > 150 km. A simplified representation is shown in Fig A2. The station has several autotransformers which have been lumped into a single equivalent autotransformer. The series capacitor bank is assumed to be out of service (bypassed).

Currents *I1* and *I2* represent the GIC contribution of the 500 kV circuits to the HV bus. Then,

$$I3 = I1 - I2 \quad \text{(A.1)}$$

where *I3* is the total contribution of the 500 kV circuits to the series winding. The total contribution to the common winding is given by

$$Ig = I3 + I4 + I5 + I6 - I7 \quad \text{(A.2)}$$

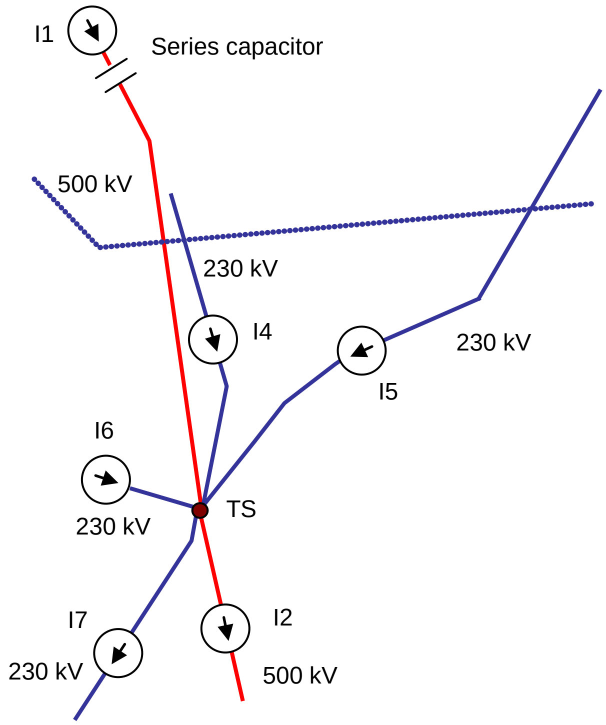

Fig. A1: HV transmission lines connecting to Essa TS.

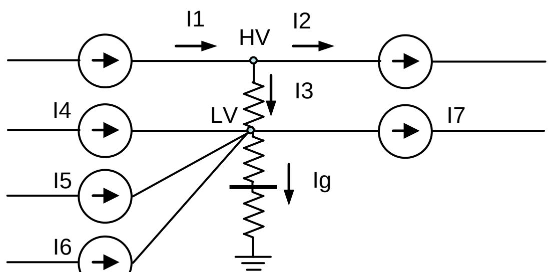

Fig. A2: Circuit representation of induced geoelectric fields and equivalent transformer representation.

Let us assume that the earth can be represented by a laterally-uniform earth model, and that the 500 kV circuits are in the same or similar orientation geographically with the same resistance per unit length, so that the injected GIC I1 and I2 are nearly identical (see Fig. A1). Then I3 will be small or zero and only the 230 kV circuits will contribute to the current in the transformer common winding Ig. If the 230 kV circuits were excluded, (i.e., I4 = I5 = I6 = I7 = 0) then I3 = Ig would be very small and the estimated effects of GIC on the autotransformer would be minimal.

If the 500 kV series capacitor bank in Fig. A1 is placed in service, then I1 = 0 and I2 = I3. The common-winding GIC is now equal to the sum of the GIC contributed by the 230 kV circuits and the remaining 500 kV circuit. Depending on the relative values of the contributions, the net GIC through the transformer may increase or decrease. Simulations show that in the network shown in Figure A1 when the series capacitors are in service, the effective GIC through the transformer increases by a factor of 30. This is not a general result, but rather a consequence of Kirchhoff's current law and a particular system topology.

If the series capacitor bank is in service and the 230 kV circuits are not taken into consideration all the GIC from the remaining 500 kV circuit would flow into the autotransformer and describe a completely different situation from in terms of the saturation of the autotransformer.

The cases described above were simulated with a GIC analysis tool and summarized in Table A1. Note that there are two 500/230 kV autotransformers in service in this simulation.

Table A1: Summary of the Effects of 230 kV Circuits in a Station with Two 500/230 kV Autotransformers

Geoelectric field 5 V/km	230 kV and 500 kV 500 kV Series caps in service	230 kV and 500 kV 500 kV Series caps bypassed	No 230 kV 500 kV Series caps in service	No 230 kV 500 kV Series caps bypassed
Transformer GIC/phase (A/phase)	99.9	2.8	127	5.5
I1 (A/phase)	0	365	0	338
I2 (A/phase)	146.8	334	254	349
Incremental metallic hot spot temperature (C°)	89	1.6	60	7.6
var absorption (Mvar)	128	14	151	12.5
THD (%)	17	2.5	18	2.2

The conclusion from this example is that it is not always possible to make generalizations in a network of relatively complex topology. While it is true that a series capacitor blocks GIC in the transmission line

where it is employed, it does not necessarily reduce GIC in system transformers. Furthermore, not taking into account the effects of the 230 kV circuits in this network would lead to inaccurate conclusions, such as a 33% underestimation of the hot spot temperature rise[1].

Example 2: Effects of the inclusion/exclusion of circuits below 200 kV

A portion of the Eastern Interconnect that contains 500 kV, 230 kV, 161 kV, and 115 kV facilities was modeled using PowerWorld software. When the GIC contribution of the 161 kV and 115 kV circuits was excluded, the effects on the network above 200 kV where found to be minimal. Table A2 summarizes the effects of including/excluding GIC contributions from the 161 kV and 115 kV network assuming a 5 V/km East-West geoelectric field. The differences in the results assuming a North-South geoelectric field are very similar, and are not reproduced in here.

Table A2: GIC Effects on the Network Above 200 kV Assuming an East-West 5 V/km Geoelectric Field

	Including 115 kV	Excluding 115 kV	Difference
Maximum transformer GIC (A/phase)	134.65	133.78	0.6 (%)
Average transformer GIC (A/phase)	13.79	13.46	2.4 (%)
Maximum transformer var absorption (Mvar)	150.3	149.5	0.7 (%)
Average transformer var absorption (Mvar)	7.16	7.08	1.1 (%)
Minimum bus voltage (pu)	0.98204	0.98548	0.4 (%)
Average bus voltage (pu)	1.01858	1.01897	0.04 (%)
Total system var loss due to GIC (Mvar)	3,935	3,801	3.4 (%)

These results are consistent with observations made in peer-reviewed technical publications such as [9].

[1] Hot spot heating was estimated using the methodology described in [15]

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Functional Entity Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators (RC) and Transmission Operators (TOP) with networks that contain power transformers with high side grounded wye windings above 200 kV. This applicability is consistent with the NERC Functional Model and existing standards where both entities are described as having responsibility and authority for reliable transmission operations within their scope. The drafting team determined that Balancing Authorities (BA) should not be among the applicable functional entities because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The drafting team also determined that Generator Operators (GOP) should not be among the applicable functional entities because any Operating Procedures to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment. Consistent with FERC Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03 and applicability of stage 2 standards will be considered separately.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779. While the applicability of the proposed stage 1 standard is limited to RCs and TOPs, other entities will be considered for stage 2 as outlined in the Standards Authorization Request.

Justification for Applicable Functional Entities

Reliability Coordinator

The RC has responsibility and authority for reliable operation within the Reliability Coordinator Area (RCA). The RC's scope includes a wide-area view with situational awareness of neighboring RCAs. The NERC Functional Model states:

> The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

The RC's authority is codified in IRO-001-1a which states:

> **R3.** The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
>
> **R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

Including the RC as an applicable entity in EOP-010-1 provides the necessary coordination for planning and real-time actions that is envisioned by the Functional Model and addresses Order No. 779 directives to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view.

Transmission Operator

Like the RC, the TOP has responsibility and authority for the reliable operation of the transmission system within a specified area. According to the NERC Functional Model:

> The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The TOP's authority is established in TOP-001-1a as follows:

> **R1.** Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.
>
> **R3**. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

The 2012 GMD Report contains web links for some TOP Operating Procedures to mitigate the effects of GMD events. Recently the GMD Task Force developed Operating Procedure templates that provide a technical resource for TOPs to use in developing procedures based on industry best practices. Included in the templates are actions that could be employed to mitigate the effects of GMD, such as reduction of equipment loading, increasing reactive reserves, reconfiguration of the system, recalling outages, and Load shedding. The templates also describe indicators of GMD conditions that could be used as trigger conditions for steps or tasks in an entity's Operating Procedures. Detailed study of system and equipment impacts can improve Operating Procedures. However, some procedures can be put in place without system studies to increase situational awareness and posture the system when a GMD event is forecasted.

Justification for Omitting Functional Entities

Balancing Authority

BAs are responsible for the Real-time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the TOP to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits.

The BA can be expected to address GMD impacts through use of generation. However, the BA would not initiate actions unilaterally during a GMD event and would instead respond to the direction of the TOP

and RC. As such, the independent actions that the BA would take are very limited, if any. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and the concurrence of the TOP and/or RC.

The RC and TOP will be preparing GMD Operating Plans, Operating Processes, and/or Operating Procedures to address steps that each will be taken to address GMD impacts. Some of those steps will require the BA to take action. As outlined above, the requirement for the BA to execute actions at the request of the TOP or RC is clear. Given that the BA would only take action at the request of the TOP or RC and that the required actions would be the same actions BAs take for other system events, the SDT concludes that the BA should not be included as an applicable entity in EOP-010-1.

Generator Operator

GOPs are the functional entity that operate generating unit(s) and perform the functions of supplying energy and reliability related services. They may be responsible for operating generator step up (GSU) transformers that connect the generator to the transmission system. Some GSU transformers are susceptible to geomagnetically-induced currents (GICs) during a GMD event, and operating actions are used by some GOPs to mitigate system or equipment impacts.

An effective GOP GMD Operating Procedure to mitigate the effects of GMD would require:

1. GSU transformer study to determine expected GIC on the GSU high side neutral level at their site (GIC/thermal rating study)
2. Ability to monitor GIC at the GSU high voltage wye-grounded winding neutral

Absent the above information, the GOP would not have the technical basis for taking steps on its own and would instead take steps based on the RC or TOP’s Operating Plans, Processes, or Procedures. Therefore, the SDT concludes that GOPs should be excluded as applicable entities in EOP-010-1.

Some GOPs already have GMD Operating Procedures for their equipment based on prior studies and/or monitoring equipment. EOP-010-1 will not prohibit or interfere with a GOP's established procedure. Furthermore, the RC and TOP will be preparing GMD Operating Plans and Operating Processes or Procedures, respectively. Those will address steps that each will be taking to address GMD impacts, which may include requiring one or more GOPs to take action. Existing standards provide obligations for the GOP to execute actions when requested by the TOP or RC as described above.
Generator Owners (GOs) and GOPs are included in the Project 2013-03 Standards Authorization Request. They will be considered for inclusion in Stage 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. Such mitigation strategies could include the development of Operating Procedures for applicable GOs and GOPs.

NERC
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RELIABILITY CORPORATION

Functional Entity Applicability

Project 2013-03 (Geomagnetic Disturbance Mitigation)
EOP-010-1 (Geomagnetic Disturbance Operations)

Summary Determination

The purpose of EOP-010-1 (Geomagnetic Disturbance Operations) is to mitigate the reliability impacts of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures. The proposed standard is applicable to Reliability Coordinators (RC) and Transmission Operators (TOP) with networks that contain power transformers with high side grounded wye windings above 200 kV.~~with networks above 200 kV~~. This applicability is consistent with the NERC Functional Model and existing standards where both entities are described as having responsibility and authority for reliable transmission operations within their scope. The drafting team determined that Balancing Authorities (BA) should not be among the applicable functional entities because there were no additional steps or tasks for a BA to perform beyond their normal balancing functions to mitigate GMD events. The drafting team also determined that Generator Operators (GOP) should not be among the applicable functional entities because any Operating Procedures to mitigate the effects of GMD would need to be supported by an equipment-specific study and is expected to require GMD monitoring equipment. Consistent with FERC Order No. 779, vulnerability assessments and mitigation plans will be addressed in stage 2 of Project 2013-03 and applicability of stage 2 standards will be considered separately.

Background

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

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 2014. An implementation period of six-months was recommended in the FERC Order.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 2015. A specific implementation period for Stage 2 was not addressed in Order 779.

EOP-010-1 is a new standard to specifically address the stage 1 directives in Order No. 779. While the applicability of the proposed stage 1 standard is limited to RCs and TOPs, other entities will be considered for stage 2 as outlined in the Standards Authorization Request.

Justification for Applicable Functional Entities

Reliability Coordinator

The RC has responsibility and authority for reliable operation within the Reliability Coordinator Area (RCA). The RC's scope includes a wide-area view with situational awareness of neighboring RCAs. The NERC Functional Model states:

> The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's wide-area view. The wide-area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

The RC's authority is codified in IRO-001-1a which states:

> **R3.** The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
>
> **R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

Including the RC as an applicable entity in EOP-010-1 provides the necessary coordination for planning and real-time actions that is envisioned by the Functional Model and addresses Order No. 779 directives to consider the coordination of Operating Procedures across regions by a functional entity with a wide-area view.

Transmission Operator

Like the RC, the TOP has responsibility and authority for the reliable operation of the transmission system within a specified area. According to the NERC Functional Model:

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The TOP's authority is established in TOP-001-1a as follows:

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

The 2012 GMD Report contains web links for some TOP Operating Procedures to mitigate the effects of GMD events. Recently the GMD Task Force developed Operating Procedure templates that provide a technical resource for TOPs to use in developing procedures based on industry best practices. Included in the templates are actions that could be employed to mitigate the effects of GMD, such as reduction of equipment loading, increasing reactive reserves, reconfiguration of the system, recalling outages, and Load shedding. The templates also describe indicators of GMD conditions that could be used as trigger conditions for steps or tasks in an entity's Operating Procedures. Detailed study of system and equipment impacts can improve Operating Procedures. However some procedures can be put in place ~~by all TOPs~~ without system studies to increase situational awareness and posture the system when a GMD event is forecasted.

Justification for Omitting Functional Entities

Balancing Authority

BAs are responsible for the Real-time balancing of the system. In order to carry out that responsibility, BAs will dispatch generation, use regulation and other ancillary services, to keep Area Control Error (ACE) within reasonable limits while maintaining system frequency. BAs will work with the TOP to adjust voltage schedules or redispatch generation at the request of the TOP to ensure that the transmission system is operated within thermal, voltage, and stability limits.

The BA can be expected to address GMD impacts through use of generation. However, the BA would not initiate actions unilaterally during a GMD event and would instead respond to the direction of the TOP and RC. As such, the independent actions that the BA would take are very limited, if any. For example, if redispatch of generation or adjustment of voltage schedules were needed, the BA would not take those actions without a request and the concurrence of the TOP and/or RC.

The RC and TOP will be preparing GMD Operating Plans, Operating Processes, and/or Operating Procedures to address steps that each will be taken to address GMD impacts. Some of those steps will require the BA to take action. As outlined above, the requirement for the BA to execute actions at the request of the TOP or RC is clear. Given that the BA would only take action at the request of the TOP or RC and that the required actions would be the same actions BAs take for other ~~sytem~~system events, the SDT concludes that the BA should not be included as an applicable entity in EOP-010-1.

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An effective GOP GMD Operating Procedure to mitigate the effects of GMD would require:

1. GSU transformer study to determine expected GIC on the GSU high side neutral level at their site (GIC/thermal rating study)
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Absent the above information, the GOP would not have the technical basis for taking steps on its own and would instead take steps based on the RC or TOP's Operating Plans, Processes, or Procedures. Therefore, the SDT concludes that GOPs should be excluded as applicable entities in EOP-010-1.

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Generator Owners (GOs) and GOPs are included in the Project 2013-03 Standards Authorization Request. They will be considered for inclusion in Stage 2 standards, which will require applicable entities to conduct vulnerability assessments and develop appropriate mitigation strategies. Such mitigation strategies could include the development of Operating Procedures for applicable GOs and GOPs.

Geomagnetic Disturbance Operating Procedure Template

Transmission Operator

Overview

Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of geomagnetically induced currents (GIC) on system reliability. They also have the merit of being relatively easy to change as new information and understanding concerning this threat becomes available. Operating procedures need to be easily understood by, and provide clear direction to, operating personnel. This is especially true since most operators are unlikely to frequently respond to significant GMD events.

Some actions listed below should only be undertaken if supported by an adequate GIC impact study and/or if adequate monitoring systems are available. Otherwise they can make matters worse. Those actions are indicated by the phrase "if supported by studies".

Determining that a geomagnetic disturbance (GMD) is significant enough to warrant the initiation of special operating procedure(s) depends on the geographical location of the power system/equipment in question coincident with the location of the GMD measurement and forecast. Amount of advance notice obviously factor heavily in what specific actions can and should be taken. Note these are recommended actions; specific actions may vary by system configuration, system design and geographic location of the entity.

Information and Indications

The following are triggers that could be used to initiate operator action:

- External:
  - NOAA Space Weather Prediction Center or other organization issues:
    - Geomagnetic storm Watch (1-3 day lead time)
    - Geomagnetic storm Warning (as early as 15-60 minutes before a storm, and updated as solar storm characteristics change)
    - Geomagnetic storm Alert (current geomagnetic conditions updated as k-index thresholds are crossed)
- Internal:
  - System-wide:
    - Reactive power reserves
    - System voltage/MVAR swings/current harmonics
  - Equipment-level:

- GIC measuring devices
- Abnormal temperature rise (hot-spot) and/or sudden significant gassing (where on-line DGA available) in transformers
- System or equipment relay action (e.g., capacitor bank tripping)

Actions Available to the Operator

The following are possible actions for Transmission Operators based on available lead-time:

Long lead-time (1-3 days in advance, storm possible)

1. Increase situational awareness
   a. Assess readiness of black start generators and cranking paths
   b. Notify field personnel as necessary of the potential need to report to individual substations for on-site monitoring (if not available via SCADA/EMS)
2. Safe system posturing (only if supported by study; allows equipment such as transformers and SVCs to tolerate increase reactive/harmonic loading; reduces transformer operating temperature, allowing additional temperature rise from core saturation; prepares for contingency of possible loss of transmission capacity)
   a. Return outaged equipment to service (especially series capacitors where installed)
   b. Delay planned outages
   c. Remove shunt reactors
   d. Modify protective relay settings based on predetermined harmonic data corresponding to different levels of GIC (provided by transformer manufacturer).

Day-of-event (hours in advance, storm imminent):

1. Increase situational awareness
   a. Monitor reactive reserve
   b. Monitor for unusual voltage, MVAR swings, and/or current harmonics
   c. Monitor for abnormal temperature rise/noise/dissolved gas in transformers[1]
   d. Monitor geomagnetically induced current (GIC[2]) on banks so-equipped[3]
   e. Monitor MVAR loss of all EHV transformers as possible

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[1] Requires proper instrumentation (e.g., fiber to hot-spot). Note there may be unusual heating in a location other than the normal hot-spot location. Dissolved gas analysis may be available in real-time if the transformer is so-equipped; otherwise, post-event DGA may be performed.
[2] 10 amperes per phase GIC is a good starting point for potential impacts on heavily loaded transformers when actual limits are unknown. Newer transformers may have significantly higher GIC withstand capability if specified at the time of construction. For vulnerable transformers, the OEM can perform analytical withstand studies to better define a particular design's GIC vs. Time withstand capability
[3] Regarding the effects of GIC on transformers, real-time mitigation (after a storm is already in progress) should not be taken based solely on a single indicator (e.g., increased GIC). At least one additional indicator should be monitored to determine if the transformer is actually being adversely affected (e.g., increased MVAR loss, abnormal temperature rise, etc)

   f. Prepare for unplanned capacitor bank/SVC/HVDC tripping[4]
   g. Prepare for possible false SCADA/EMS indications if telecommunications systems are disrupted (e.g., over microwave paths)
2. Safe system posturing (only if supported by study)
   a. Start off-line generation, synchronous condensers
   b. Enter conservative operations with possible reduced transfer limits
   c. Ensure series capacitors are in-service (where installed)

Real-time actions (based on results of day-of-event monitoring):

1. Safe system posturing (only if supported by study)
   a. Selective load shedding[5]
   b. Manually start fans/pumps on selected transformers to increase thermal margin (check that oil temperature is above 50° C as forced oil flow at lower temperatures may cause static electrification)
2. System reconfiguration (only if supported by study)
   a. Remove transformer(s) from service if imminent damage due to overheating (possibly automatic by relaying)
   b. Remove transmission line(s) from service (especially lines most influenced by GMD)

Return to normal operation

This should occur two to four hours after the last observed geomagnetic activity.

Related Documents and Links

2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbance on the Bulk Power System, dated February 2012
http://www.nerc.com/files/2012GMD.pdf

Industry Advisory: Preparing for Geomagnetic Disturbances, dated May 10, 2011
http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf

[4] Consideration should be given to replacing protective relaying (as part of planned GIC mitigation projects) to prevent false tripping of reactive assets due to GIC should be considered. Note that capacitor units have harmonic overload limits that should be observed (see IEEE Std 18).
[5] Giving preference of course to the most critical/sensitive loads (e.g., national security, nuclear fuel storage site, nuclear plant offsite sources, chemical plants, emergency response centers, hospitals, etc)

Agenda Item 8
Standards Committee
October 17, 2013

Project 2013-03 Geomagnetic Disturbance (GMD) Mitigation

Action

Authorize a contingent waiver of the Standard Processes Manual (SPM) that shortens the final (recirculation) ballot period for the stage 1 standard, EOP-010-1– Geomagnetic Disturbance Operations, from 10 days to seven days to meet the FERC-directed filing schedule and NERC Board of Trustees (Board) meeting schedule, to be exercised only if 1) EOP-010-1 receives sufficient support during the current ballot to proceed to final (recirculation) ballot, and 2) the shortened time is necessary (as jointly determined by the NERC Standards Developer, PMOS Liaison and Chair of the SDT) to provide the drafting team adequate opportunity to fully consider stakeholder comments and prepare and review documents for posting for the final ballot.

Background

On May 16, 2013, FERC issued Order 779 directing NERC to develop and submit Reliability Standards addressing the potential impact of GMDs in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. Stage 1 Standard(s) must be filed by January 21, 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 Standards must be filed by January 21, 2015.

The initial draft of EOP-010-1 was posted for 45-day formal comment period and initial ballot through August 12, 2013, and received a weighted segment approval of 62.74%. A revised draft of EOP-010-1 was posted for 45-day formal comment and additional ballot on September 4, 2013. The ballot period ends on October 18, 2013. The drafting team is scheduled to meet October 23-24, 2013 to consider comments and revise the draft standard if necessary.

The NERC Board meeting on November 7, 2013 is the last scheduled board meeting prior to the FERC filing deadline for the stage 1 standard. Because of the high profile nature of Project 2013-03 (GMD Mitigation), the drafting team recognizes that it is particularly appropriate for the standard to be submitted to the NERC Board for adoption during the Board’s quarterly meeting, if possible. This will ensure the standard is considered for adoption under NERC's normal open and transparent process without special arrangements for a NERC Board conference call.

The drafting team has maintained a rigorous development and communication effort in order to reach the November NERC Board meeting milestone. In order to complete a 10-day final ballot in time for the Board to adopt EOP-010-1 at that meeting, the team would need to post for the final ballot on Friday, October 25. If EOP-010-1 receives sufficient approval during the current ballot, a waiver of the SPM that would shorten the final ballot period from 10 days to seven days would provide a significant amount of additional time for the team to review the final set of documents prior to posting, by allowing them to post as late as October 30.

As required in Section 16.0 of the SPM, NERC provided stakeholders with notice of this waiver request on October 10, 2013. If the waiver is authorized, NERC staff will post notice of the waiver on the project page and notify the NERC Board of Trustees Standards Oversight and Technology Committee.

Violation Risk Factor and Violation Severity Level Justifications

EOP-010-1 – Geomagnetic Disturbance Operations

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-010-1 – Geomagnetic Disturbance Operations.

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

The Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk

Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

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

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

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

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

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

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

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

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

NERC Criteria - Violation Severity Levels

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

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justifications – EOP-010-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to implement a GMD Operating Plan when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, failure to implement a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. Failure to develop or maintain a GMD Operating Plan could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, failure to develop or maintain a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the importance of having coordinated GMD Operating Procedures and the RC's role in the planning and operations time horizons.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned. The requirement uses Parts to identify the items to be included in a GMD Operating Plan. The VRF for this requirement is consistent with Requirement R3 with regard to relative risk.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with IRO 014-1 Requirement R1, which requires the Reliability Coordinator to have Operating Procedures, Processes, or Plans in place to support interconnection reliability. The drafting team believes the reliability objective of IR0-014-1 Requirement R1 is most comparable to the proposed Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A Violation Risk Factor of Medium is consistent with NERC VRF definition. Failure to implement a GMD Operating Plan when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, failure to implement a GMD Operating Plan is unlikely to lead to BES instability, separation,

VRF Justifications – EOP-010-1, R1	
	or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. Failure to develop or maintain a GMD Operating Plan could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, failure to develop or maintain a GMD Operating Plan is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the significance of the RC's role in coordinating GMD Operating Procedures in the planning and operations time horizons.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The assigned risk level reflects the most important objective of the requirement.

Proposed VSLs – EOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area

VSL Justifications – EOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent	The proposed VSL is worded consistently with the corresponding requirement.

with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justifications – EOP-010-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to disseminate forecasted and current space weather information could directly and adversely affect the electrical state or capability of the Bulk Electric System during a GMD event. However, failure to disseminate forecasted and current space weather information is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. This requirement and VRF reflects the drafting team's view of the significance of consistent space weather information for coordination of GMD Operating Procedures in each Reliability Coordinator Area and maintains responsibility for providing this information on the Reliability Coordinator as established in IRO-005-3.1a.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements and a single VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with IRO-008-1 Requirement R3 which requires the Reliability Coordinator to share information with specific entities that are expected to take operational actions when a potential Interconnection

VRF Justifications – EOP-010-1, R2	
	Reliability Operating Limit violation is anticipated. Dissemination of space weather forecast information can be considered a similar information sharing activity with an impact that would not exceed IRO-008-1 Requirement R3.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. Failure to disseminate forecasted and current space weather information could directly and adversely affect the electrical state or capability of the Bulk Electric System during a GMD event. However, failure to disseminate forecasted and current space weather information is unlikely to lead to BES instability, separation, or cascading failures. The Reliability Coordinator and applicable entities are responsible for maintaining the reliability of the BES under all circumstances. This requirement and VRF reflects the drafting team's view of the significance of consistent space weather information for coordination of GMD Operating Procedures in each Reliability Coordinator Area and maintains responsibility for providing this information on the Reliability Coordinator as established in IRO-005-3.1a.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – EOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.

VSL Justifications – EOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The drafting team believes that a single VSL is most appropriate for describing noncompliant performance of the requirement. Dissemination of space weather information will most likely be accomplished using automated communication systems such as all-call or electronic distribution lists. As a result the RC's compliance will be evaluated on a binary basis for implementing a notification system to disseminate space weather information.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL. IRO-005-3.1a requirement R3 provided a similar compliance obligation without a FERC-approved VSL.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL assignment category for a binary requirement is consistent. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications – EOP-010-1, R2	
Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on number of violations.

VRF Justifications – EOP-010-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to implement a GMD Operating Procedure or Operating Process when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, this failure is unlikely to lead to BES instability, separation, or cascading failures. The Transmission Operator and other applicable entities are responsible for maintaining the reliability of the BES under within their respective areas in all circumstances. Failure to develop or maintain a GMD Operating Procedure or Operating Process could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, this failure is unlikely to lead to BES instability,

VRF Justifications – EOP-010-1, R3	
	separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the importance of developing and maintaining coordinated and predetermined operating procedures or processes in the planning horizon, and for implementing the operating procedures or processes when conditions warrant in the operations time horizon.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned. The requirement uses Parts to identify the items to be included in a GMD Operating Procedure or Operating Process. The VRF for this requirement is consistent with Requirement R1 with regard to relative risk.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A Violation Risk Factor of Medium is consistent with EOP 001-2.1b, requirement R2.2 which requires the Transmission Operator to develop, maintain, and implement plans to mitigate operating emergencies on the transmission system. Additionally, it is consistent with IRO 014-1 Requirement R1, which requires the Reliability Coordinator to have Operating Procedures, Processes, or Plans in place to support interconnection reliability. Although the functional entities are different, the reliability objective of IR0-014-1 Requirement R1 is comparable to the proposed Requirement R3.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. Failure to implement a GMD Operating Procedure or Operating Process when warranted by conditions could directly affect the electrical state or the capability of the Bulk Electric System (BES). However, this failure is unlikely to lead to BES instability, separation, or cascading failures. The Transmission Operator and other applicable entities are responsible for maintaining the reliability of the BES under within their respective areas in all circumstances. Failure to develop or maintain a GMD Operating Procedure or Operating Process could, under anticipated conditions, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, this failure is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to normal conditions. This VRF reflects the drafting team's view of the

VRF Justifications – EOP-010-1, R3	
	importance of developing and maintaining coordinated and predetermined operating procedures or processes in the planning horizon, and for implementing the operating procedures or processes when conditions warrant in the operations time horizon.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The assigned risk level reflects the most important objective of the requirement.

Proposed VSLs – EOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator had a GMD Operating Procedure or Operating Process, but failed to maintain it.	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	The Transmission Operator's GMD Operating Procedure or Operating Process failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	The Transmission Operator did not have a GMD Operating Procedure or Operating Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

VSL Justifications – EOP-010-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of	There is no prior compliance obligation related to the subject of this standard.

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

Order No. 779 Citation	Directive/Guidance	Resolution in EOP-010-1
P 36	The Commission directs NERC to submit, within six months of the effective date of this Final Rule, one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System.	Requirement R1 requires Reliability Coordinators to develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. Requirement R3 requires Transmission Operators to develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. Analysis of the applicable functional entities is provided in a white paper posted on the project page. (http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx)
P 38	The Commission is not directing NERC to develop Reliability Standards that include specific operational procedures. Instead, as proposed in the NOPR, the Reliability Standards should include a mechanism that requires responsible entities to develop and implement operational procedures because owners and operators of the Bulk-Power System are most familiar with their own equipment and system configurations. In addition, we do not expect that owners and operators of the Bulk-Power System will necessarily develop and implement the same operational procedures. Instead, the Reliability Standards, rather than include "one-size-fits-all" Requirements, should allow responsible entities to tailor their operational procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology, identified in the Reliability Standards. In addition, as we stated in the NOPR, the coordination of operational procedures across regions is an important issue that should be considered in the NERC standards development process.[68] The coordination	EOP-010-1 is not prescriptive and allows entities to tailor their Operational Procedures or Operating Processes based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology. Requirement R1 addresses coordination and requires Reliability Coordinators to develop, maintain and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. The coordination of Operating Procedures and

Order No. 779 Citation	Directive/Guidance	Resolution in EOP-010-1
	of operational procedures across regions and data sharing might be overseen by planning coordinators or another functional entity with a wide-area perspective.[69] The NERC standards development process, as stated in the NOPR, should also consider operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for damaged equipment that could be de-rated or out-of-service for an extended period of time.	Operating Processes across regions is addressed through existing Reliability Standards. EOP-005 (System Restoration from Blackstart Resources) and EOP-006 (System Restoration Coordination) address Bulk-Power System restoration following a Disturbance. These plans are expected to be effective for restoration following any unplanned event. A duplicative requirement was not included in EOP-010-1.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

A Final Ballot is now open through November 4, 2013

Now Available

A final ballot for **EOP-010-1** – **Geomagnetic Disturbance Operations** is open through **8 p.m. Eastern on Monday, November 4, 2013.**

On October 17, 2013, the Standards Committee approved a waiver of the Standard Processes Manual to shorten the final ballot from ten days to seven days only if necessary. After reviewing the comments, the standard drafting team determined that they would not need to exercise the waiver and the standard could be posted for the usual 10-day final ballot in order to meet the FERC-directed filing schedule and NERC Board of Trustees meeting schedule.

Background information for this project can be found on the project page.

Instructions
In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps
Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation
EOP-010-1

Final Ballot Results

Now Available

A final ballot for **EOP-010-1 – Geomagnetic Disturbance Operations** concluded at **8 p.m. Eastern on Monday, November 4, 2013**.

This standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval
Quorum: 86.90%
Approval: 91.95%

Background information for this project can be found on the project page.

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2013-03 GMD Final Ballot October 2013
Ballot Period:	10/25/2013 - 11/4/2013
Ballot Type:	Final Ballot
Total # Votes:	345
Total Ballot Pool:	397
Quorum:	**86.90 % The Quorum has been reached**
Weighted Segment Vote:	91.95 %
Ballot Results:	**The standard has passed**

ummary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	79	0.919	7	0.081	0	9	10
2 - Segment 2	10	0.7	7	0.7	0	0	0	1	2
3 - Segment 3	91	1	66	0.971	2	0.029	0	10	13
4 - Segment 4	30	1	17	0.81	4	0.19	0	4	5
5 - Segment 5	89	1	61	0.91	6	0.09	0	12	10
6 - Segment 6	54	1	37	0.902	4	0.098	0	3	10
7 - Segment 7	1	0.1	1	0.1	0	0	0	0	0
8 - Segment 8	6	0.5	4	0.4	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**397**	**7.3**	**282**	**6.712**	**24**	**0.588**	**0**	**39**	**52**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	

1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Transmission Agency of Northern California	Bryan Griess		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	SUPPORTS THIRD PARTY COMMENTS
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Public Power Association	Nathan Mitchell	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	

3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City Water, Light & Power of Springfield	Roger Powers	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	Manitowoc Public Utilities	Thomas E Reed		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Abstain	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	

3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	

5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Negative	COMMENT RECEIVED
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	SUPPORTS THIRD PARTY COMMENTS - SERC OC Review Group
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County,	Michiko Sell		

	Washington			
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	

6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Abstain	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Affirmative	
8	Foundation for Resilient Societies	William R Harris	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Michigan Public Service Commission	Donald J Mazuchowski		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit I

Standard Drafting Team Roster

Project 2013-03 Geomagnetic Disturbance Mitigation

Name and Title	Company	Contact Info	Bio
Frank Koza, P.E. Chair Executive Director of Infrastructure Planning	PJM Interconnection	610.666.4228 kozaf@pjm.com	Executive Director of Infrastructure Planning and in charge of the technical staff associated with generator interconnection and implementation of transmission enhancements. Vice Chair of GMD Task Force. At PJM over 12 years, previously in charge of system operations. Former Chair of the NERC Operating Reliability Subcommittee and Reliability Assessments Subcommittee. Before PJM, worked for 29 years at Exelon/PECO Energy in a variety of assignments including construction of fossil and nuclear generation facilities, construction and maintenance of transmission, system planning, and system operations. MS Engineering
Randy Horton, Ph.D., P.E. Vice Chair Chief Engineer, Transmission Technical Support	Southern Company Services	205.257.6352 jrhorton@ southernco.com	Chief Engineer of Southern Company Services Transmission Technical Support. Leader of GMD Task Force GIC Model Development team. Held various engineering positions within the Protective Equipment Applications (system protection) and Technical Studies groups of Alabama Power Company and Southern Company Services, progressing to Principal Engineer. EPRI lead researcher in the NERC and DOE sponsored GMD project which included the development of software tools and methods used to analyze the impacts of a severe GMD on the bulk electric system. Developed and published a geomagnetically induced current (GIC) benchmark model that has

			been used by commercial software vendors and others to develop and validate GIC models. Senior Member of the IEEE and Member of CIGRE. Chair of the IEEE Working Group on Field Measured Overvoltages, Secretary of IEEE Std. 519 (harmonics), Co-Chair of the IEEE GMD Task Force, Advisory Council Member for EPRI's Substations Research Program.
Donald Atkinson, P.E. Relay and Control Designer and System Protection Engineer	Georgia Transmission Corporation	770.270.7178 donald.atkinson@gatrans.com	Relay and Control Designer and System Protection engineer. Responsible for relay designs, calculating relay settings, conducting system planning studies, event analyses, creating relay standards, and writing transmission substation operating instructions. BS in Electrical Engineering (power systems).
Emanuel Bernabeu, Ph.D., P.E. Lead Power Engineer, Special System Studies	Dominion Technical Solutions, Inc	804-257-4017 emanuel.e.bernabeu@dom.com	Lead power engineer for special system studies at Dominion. Member of the GMD Task Force Equipment Modeling team. Responsible for Dominion's GMD risk assessment and mitigation strategy with extensive experience regarding modeling, planning, situational awareness, and operational procedures for GMD. Experience with GIC system calculations, voltage stability analysis, equipment vulnerability, and mitigation planning. Senior engineer for projects in transient over-voltages (TOV), EMI, "Aurora" cyber/physical attack, N-1-1 contingency analysis, black-start stability assessment, Phasor Measurements Units (PMUs) applications, and root cause analysis of protection relay misoperations. Member of NERC's Severe Impact Resilience Task Force (SIRTF).

Kenneth Fleischer, P.E. Nuclear Chief Electrical / I&C Engineer	NextEra Energy	561.691.2456 kenneth.fleischer@fpl.com	Nuclear Chief Electrical Engineer responsible for Electrical/I&C activities for two south Florida nuclear sites and three nuclear sites in upper North America. Member of GMD Task Force. Experience with solar mitigation activities during Solar Cycle 23 while employed at another nuclear power complex in New Jersey that had developed mitigation procedures from the 1989 solar events that damaged several generator step up transformers. Joined FPL in 2005, and took his solar mitigation experience and applied it to the northern nuclear sites in order to protect their generator step up transformers from extreme solar geomagnetic disturbance events. This included equipment, transformer GIC rating calculations/studies and detailed GMD mitigation procedures.
Luis Marti, Ph.D., PE Manager, Professional Development and Special Studies	Hydro One Networks	416.345.5317 luis.marti@HydroOne.com	Manager, Professional development and special studies, Hydro One. Leader of GMD Task Force Equipment Modeling Team. Research/study activities include the development of models for the family of EMTP programs, GIC simulation, grounding, induction coordination, EMF issues pertaining to T&D networks, and connection/operational issues around the connection of renewable generation in distribution networks. Participated in a number of Canadian and international technical organizations such as CSA (Canadian Standards Association, IEEE, and CIGRE). Adjunct professor at the universities of Western Ontario and Ryerson.

Antti Pulkkinen, Ph.D.	NASA Goddard Space Flight Center		Director of Space Weather Research Center (SWRC). Leader of GMD Task Force Space Weather Science team developing reference storm scenarios. Published 1-in-100 year storm scenarios used in the 2012 GMD Interim Report and presented at various space weather technical conferences. PhD and postdoctoral research involved studies of ground effects of space weather and complex nonlinear dynamics of the magnetosphere-ionosphere system. Leads and participates in numerous space weather-related projects where scientists have been in close collaboration with industrial partners. In many of these projects, his work has involved general geomagnetic induction modeling and modeling of space weather effects on pipelines and power transmission systems. Recently been leading the development of operational space weather forecasting activity at NASA GSFC. Worked as an Associate Director of Institute for Astrophysics and Computational Sciences and as an Associate Professor at The Catholic University of America (CUA) where he launched a new Space Sciences and Space Weather program crafted to educate next generation scientists and space weather operators.
Qun Qiu, Ph.D., P.E. Principal Engineer - Transmission Protection and Control Engineering	American Electric Power	614.552.1182 qqiu@aep.com	Principal Engineer – Transmission Protection & Control Engineering. Member of GMD Task Force Equipment Modeling team. Leading a team in implementing company-wide GIC/Harmonics monitoring system and developing GMD mitigation efforts. Keynote presenter at February GMDTF in-person meeting,

			and recent speaker on GMD at CIGRE Grid of the Future Symposium, North American Transmission Forum Board Meeting, Southwest Power Pool (SPP) Compliance Forum. Co-authored several papers on GMD monitoring, GIC modeling and simulations. Member of CIGRE; senior member of IEEE.
Mark Olson Standards Developer	NERC	404.446.9760 mark.olson@nerc.net	Standards Developer at NERC since October 2012. Previously a career officer in the U.S. Navy where he served in various positions related to the operations and management of surface ships and naval personnel. Master's degree in electrical engineering from the Naval Postgraduate School and a bachelor’s degree from the U.S. Naval Academy.